Alberta Reliability Standards

Updated: October 1, 2018

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1. Purpose

The purpose of this *reliability standard* is to maintain *WECC* steady-state frequency within defined limits by balancing real power demand and supply in real-time.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must operate such that, on a rolling 12 month basis, the average of the clock-minute averages of the *AIES's ACE* divided by 10B (B is the clock-minute average of the *AIES's frequency bias*) times the corresponding clock-minute averages of the *Interconnection's frequency error* is less than a specific limit. This limit $\varepsilon 1^2$ is a constant derived from a targeted frequency bound (separately calculated for each *Interconnection*) that is reviewed and set as necessary by the *NERC Operating Committee*.

$$AVG_{period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \underline{\Delta F_1}\right] \le \in_1^2 \quad or \quad \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \underline{\Delta F_1}\right]}{\in_1^2} \le 1$$

The equation for *ACE* is:

$ACE = (NI_A - NI_S) - 10B(F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all *tie lines*.
- NI_S is the algebraic sum of scheduled flows on all *tie lines*.
- B is the *frequency bias setting* (MW/0.1 Hz) for the *AIES*. The constant factor ten converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net *tie line* flows (NI_A) and the hourly

net i*nterchange* demand measurement (megawatt hour). This term should normally be very small or zero.

R 1.1 *Control performance standard (CPS)* 1 must be calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor (CF) is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF \quad \frac{CF_{12-month}}{(\in_1)^2}$$

where: ε1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of *ACE* (raw *ACE*, unadjusted for the *WECC* Automatic Time Error Control), *frequency error* and *frequency bias settings*.

A clock-minute average is the average of the *AIES*'s valid measured variable (i.e., for *ACE* and for *frequency error*) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10\ B}\right)_{clock\ -\min\ ute} = \frac{\left(\frac{\sum ACE_{sampling\ \ cycles\ in\ clock\ -\min\ ute}}{n_{sampling\ \ cycles\ in\ clock\ -\min\ ute}}\right)}{-10\ B}$$

The *AIES*'s clock-minute CF becomes:

$$CF_{clock\ -\min\ ute} = \left\lceil \left(\frac{ACE}{-10\ B}\right)_{clock\ -\min\ ute} * \Delta F_{clock\ -\min\ ute} \right\rceil$$

Normally, sixty (60) clock-minute averages of the *AIES*'s *ACE* of the respective *Interconnection's frequency error* will be used to calculate the respective hourly average compliance parameter.

$$CF_{clock\ -hour} = \frac{\sum CF_{clock\ -\min\ ute}}{n_{clock\ -\min\ ute\ \ samples\ \ in\ hour}}$$

The ISO must be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$CF_{clock-hour\ average-month} = \frac{\sum_{days-in-month}\left[\left(CF_{clock-hour}\right)\left(n_{one-minute}\right)\right]}{\sum_{days-in-month}\left[n_{one-minute\ samples\ in\ clock-hour}\right]}$$

$$CF_{month} = \frac{\sum_{days-in-month}\left[\left(CF_{clock-hour\ average-month}\right)\left(n_{one-minute\ samples\ in\ clock-hour\ averages}\right)\right]}{\sum_{days-in-month}\left[n_{one-minute\ samples\ in\ clock-hour\ averages}\right]}$$

The 12-month CF becomes:

$$CF_{12-month} = \frac{\sum_{i=1}^{12}\left(CF_{month-i}\right)\left(n_{(one-minute\ utes\ samples\ in\ month)-i}\right)\ ]}{\sum_{i=1}^{12}\left[n_{(one-minute\ samples\ in\ month)-i}\right]}$$

In order to ensure that the average *ACE* and *frequency deviation* calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both *ACE* and *frequency deviation* samples during that one-minute interval be present.

Should a sustained interruption in the recording of *ACE* or *frequency deviation*, due to loss of telemetering or computer unavailability, result in a one-minute interval not containing at least 50% of samples of both *ACE* and *frequency deviation*, that one-minute interval shall be excluded from the calculation of CPS1.

R2 The ISO must operate such that its average *ACE* for at least 90% of clock ten-minute periods (6 non-overlapping periods per hour) during a calendar *month* is within a specific limit, referred to as L_{10}.

$AVG_{10\ minute}(ACE_i) \leq L_{10}$

where:

$L_{10}=1.65\ \varepsilon_{10}\ \sqrt{(-10B_i)(-10B_s)}$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average *frequency error* based on frequency performance over a given year. The bound, ε_{10}, is the same for every *balancing authority* area within the *WECC*, and B_s is the sum of the *frequency bias settings* of the *balancing authority* areas in the *WECC*. For *balancing authority* areas with variable bias, this is equal to the sum of the minimum *frequency bias settings*.

R2.1 CPS2 relates to a bound on the ten-minute average of *ACE*. A compliance percentage must be calculated as follows:

$$CPS\ 2 = \left[1 - \frac{Violations_{month}}{\left(Total\ Periods_{month} - Unavailable\ Periods_{month}\right)}\right] * 100$$

The violations per month are a count of the number of periods that *ACE* clock-ten-minutes exceeded L_{10}. *ACE* clock-ten-minutes is the sum of valid *ACE* samples within a clock-ten-minute period divided by the number of valid samples. Violation clock-ten-minutes

= 0 if:

$$\left| \frac{\sum ACE}{n_{samples \quad in \ 10-\min utes}} \right| \leq L_{10}$$

$$= 1 \ if$$

$$\left| \frac{\sum ACE}{n_{samples \quad in \ 10-\min utes}} \right| \succ L_{10}$$

The *ISO* must report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that *ACE* be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of *ACE*.

In order to ensure that the average *ACE* calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the *ACE* data samples are present for that interval. Should half or more of the *ACE* data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

5. Procedures

No procedures have been defined for this *reliability standard.*

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 CPS1, as defined and calculated per R1 and R1.1, is at least 100%.

MR2 CPS2, as defined and calculated per R2 and R2.1, is at least 90%.

7. Appendices

Appendix 1 CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each *balancing authority area* in the *WECC*.	Retain the value of ε1 used in CPS1 calculation.
ACEi	The clock-minute average of *ACE* (raw *ACE*, unadjusted for the *WECC* Automatic Time Error Control)	Retain the one-minute average values of *ACE* (525,600 values).
Bi	The f*requency bias* of the *AIES*.	Retain the value(s) of Bi used in the CPS1calculation.

FA	The actual measured frequency.	Retain the one-minute average frequency values (525,600 values).
FS	Scheduled frequency for the *WECC*.	Retain the one-minute average frequency values (525,600 values).

CPS2 DATA	**Description**	**Retention Requirements**
V	Number of incidents per hour in which the absolute value of *ACE* clock-ten-minutes is greater than L10.	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each *balancing authority area* within the *WECC*.	Retain the value of ε10 used in CPS2 calculation.
Bi	The *frequency bias* of the *AIES*.	Retain the value of Bi used in the CPS2 calculation.
Bs	The sum of *frequency bias of the balancing authority areas* in the *WECC*. For systems with variable bias, this is equal to the sum of the minimum *frequency bias setting*.	Retain the value of Bs used in the CPS2 calculation. Retain the one-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

8. Guidelines

No Guidelines have been defined for this reliability standard.

Revision History

Date	**Description**
2009-02-13	New Issue

Alberta Reliability Standard
Disturbance Control Performance
BAL-002-AB-1

1. Purpose

The purpose of this **reliability standard** is to ensure the **ISO** is able to utilize its **contingency reserve** to balance resources and **demand** and return **interconnection** frequency within defined limits following a **disturbance** resulting from a loss of supply.

2. Applicability

This **reliability standard** applies to the following:

- the **ISO** which may meet the requirements of BAL-002-AB-1 through participation in a **reserve sharing group** which the **ISO** has designated as its agent.

3. Requirements

R1 The **ISO** must have access to **contingency reserves** to respond to **disturbances** resulting from a loss of supply and requiring the activation of **contingency reserves** except within the first sixty (60) minutes following the **disturbance** or except following the deployment of **contingency reserves** during implementation of the **ISO**'s capacity and energy emergency plan.

R2 The **ISO** must have access to **contingency reserves** from any, or a combination of: **generating units**, controllable **load** resources, or coordinated adjustments to **interchange schedules**.

R3 The **ISO** must have access to at least enough **contingency reserves** to cover its most severe single **contingency**.

R4 The **ISO** must activate sufficient **contingency reserve** to restore its **area control error** to the lesser of zero (0) or the pre-**disturbance** level within fifteen (15) minutes of any **reportable disturbances** subject to requirement R4.1.1 through R4.1.3.

R4.1.1 The **ISO** must treat multiple **contingencies** occurring within one (1) minute or less of each other as a single **contingency**.

R4.1.2 If the magnitude of the single **contingency** referred to in requirement R4.1.1 exceeds the **ISO**'s most severe single **contingency** the **ISO** must still consider the single contingency as a **reportable disturbance** but the ISO is excluded from compliance evaluation under requirement R4.

R4.1.3 If any subsequent **contingency** occur between one (1) minute and fifteen (15) minutes after the start of a **reportable disturbance,** any such subsequent **contingency** will be excluded from compliance evaluation under requirement R4 and the **ISO** must only determine compliance with requirement R4 for the initial **reportable disturbance** by performing a reasonable estimation of the response that would have occurred had any subsequent **contingency** not occurred.

R4.2 Subject to requirement R4.3, the **ISO** must report subsequent r**eportable disturbances** that occur fifteen (15) minutes after the initial **contingency** but

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before sixty (60) minutes after the initial **contingency** and include such **reportable disturbances** in the compliance evaluation.

R4.3 If **contingency reserves** were rendered inadequate by responding to any prior **contingency,** the **ISO** must be able to show a good faith effort to activate available **contingency reserves** however the ISO is not required to successfully restore its **area control error** to the lesser of zero (0) or the pre-**disturbance** level within fifteen (15) minutes of any **reportable disturbances**.

R4.4 The **ISO** must, no later than the tenth (10^{th}) day following the end of each calendar quarter, report all **reportable disturbances** for that quarter by submitting one (1) completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to the NERC Resources Subcommittee Survey contact.

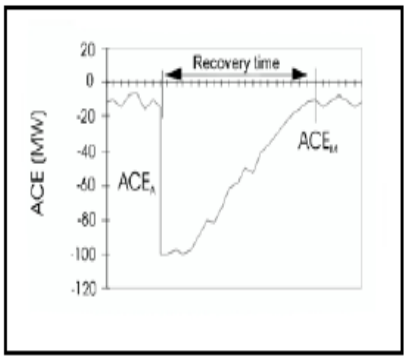
R5 The **ISO** must use the following formula to calculate the recovery of **area control error** for a **reportable disturbance**:

For loss of generation:

if $ACE_A < 0$

then

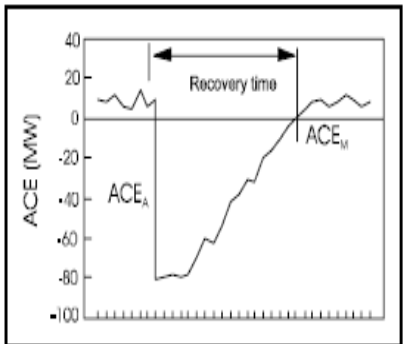
$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$



if $ACE_A \geq 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$



where:

- MW_{LOSS} is the MW size of the **disturbance,** resulting from a loss of supply, as measured at the beginning of the loss. The **ISO** must record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in **area control error** since governor response and **automatic generation control** response may introduce error.
- ACE_A is the pre-**disturbance** value of **area control error** measured as the average **area control error** over the period just prior to the start of

the **disturbance,** resulting from a loss of supply, (10 and 60 seconds prior and including at least 4 scans of **area control error**).

- ACE_M is the maximum algebraic value of **area control error** measured within the fifteen (15) minutes following the **disturbance** resulting from a loss of supply.

R6 The **ISO** must determine its prospective most severe single **contingency** at least once every calendar year by reviewing any probable **contingency** on the **interconnected electric system**.

4 Measures

The following measures correspond to the requirements identified in Section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of having access to **contingency reserves** as required in requirement R1 exists. Evidence may include records of **ancillary services** contracts or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

MR2 Evidence of supplying **contingency reserves** as required in requirement R2 exists. Evidence may include records of **ancillary services** contracts or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

MR3 Evidence of having access to **contingency reserves** as required in requirement R3 exists. Evidence may include records of **ancillary services** contracts or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

MR4 Evidence of activating **contingency reserves** as required in requirement R4 exists. Evidence may include records of calculation showing the value of parameters used for calculating the percentage recovery (Ri), the calculation formula, a chart (area control area with respect to time) and the result of the calculation or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

MR4.1 Evidence of treating multiple **contingencies** as required in requirement R4.1 exists. Evidence may include disturbance control performance reports and records of any **directive** for **ancillary services** or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

MR4.2 Evidence of determining compliance in a multiple **contingency** situation as required in requirement R4.2 exists. Evidence may include records of any **directive** for **ancillary services** or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

MR4.3 Evidence of reporting additional **reportable disturbances** as required in requirement R4.3 exists. Evidence may include disturbance control performance reports or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

MR5 Evidence of using the formula as required in requirement R5 exists. Evidence may include confirmation emails or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

MR6 Evidence of determining the prospective most severe single **contingency** as required in requirement R6 exists. Evidence may include email or **ISO** log sheet or a **reserve sharing group** agreement including a **reserve sharing group** agent appointment agreement.

5. Appendices

No appendices have been defined for this **reliability standard**.

Revision History

Effective	Description
2012-10-01	

Alberta Reliability Standard
Contingency Reserve
BAL-002-WECC-AB1-2

1. Purpose

The purpose of this **reliability standard** is to specify the quantity and types of **contingency reserve** required to ensure reliability under normal and abnormal conditions.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**, which may meet the requirements of this reliability standard through participation in a **reserve sharing group** that the **ISO** has designated as its agent.

This **reliability standard** does not apply in the case of contingencies that result in the **interconnected electric system** losing synchronism with the **western interconnection.**

3. Requirements

R1 The **ISO** must have held, at a minimum, an average amount of **contingency reserve** that is:

R1.1 the greater of either:

(a) an amount equal to the loss of the most severe single **contingency**; or

(b) an amount equal to the sum of:

three percent (3%) of the hourly integrated amount of load, being the hourly integrated amount of net generation the **ISO** determines is delivered to the grid minus **net actual interchange**;

plus

three percent (3%) of the hourly integrated amount of net generation the **ISO** determines is delivered to the grid;

where “net generation the **ISO** determines is delivered to the grid” is equal to the sum of:

(i) generation from a **generating unit** or **aggregated generating facility** but not including unit service and station service loads;

plus

(ii) generation from an industrial complex or facility that has on-site generation but not including generation serving on-site load;

plus

(iii) generation delivered to the grid by the City of Medicine Hat;

R1.2 comprised of any combination of the **operating reserve** types specified below:

(a) **spinning reserve**;

(b) **supplemental reserve**;

(c) **interchange transactions** sourced within Alberta that the **ISO** designates as **supplemental reserve**;

(d) **interchange transactions** sourced external to Alberta that the **ISO** designates as **spinning reserve** or **supplemental reserve** and that, by agreement, is deliverable to Alberta on firm transmission service;

(e) a resource, other than a **generating unit**, an **aggregated generating facility** or load, that can provide energy or reduce energy consumption;

(f) load, including demand response resources, demand-side management resources, direct control load management, interruptible load or **interruptible demand**, or any other load made available for curtailment by the **ISO** via contract or agreement; and

(g) during capacity and energy emergencies, load that can be interrupted; and

R1.3 an amount of capacity from a resource that is capable of fully responding within ten (10) minutes;

except within the first sixty (60) minutes following a **disturbance** resulting from a loss of supply and requiring the activation of **contingency reserve** or except following the deployment of **contingency reserve** during implementation of the **ISO**'s capacity and energy emergency plan.

R2 The **ISO** must maintain at least fifty percent (50%) of its minimum amount of **contingency reserve** required in requirement R1 as **spinning reserve** that is immediately and automatically responsive to frequency deviations through the action of a **governor** or other control system.

R3 The **ISO** must, when operating as a sink **balancing authority**, maintain an amount of **operating reserve**, in addition to the minimum **contingency reserve** required in requirement R1, equal to the amount of **supplemental reserve** for any **interchange transaction** designated as part of the **supplemental reserve** of the source **balancing authority** or source **reserve sharing group**, except within the first sixty (60) minutes following an event requiring the activation of **contingency reserve** or except following the deployment of **contingency reserve** during implementation of the **ISO**'s capacity and energy emergency plan.

R4 The **ISO** must, when operating as a source **balancing authority**, maintain an amount of **operating reserve**, in addition to the minimum **contingency reserve** amounts required in requirement R1, equal to the amount and type of **operating reserve** for any **operating reserve** transactions for which it is the source **balancing authority**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Evidence of having held **contingency reserve** as required in requirement R1 exists. Evidence may include:

(a) a **reserve sharing group** agreement including an agent appointment agreement, documentation of the methodology of the **contingency reserve** calculation, or **ancillary services** contracts; or

(b) records of **disturbances** or implementation of the **ISO**'s capacity and emergency plan as required in requirement R1.

MR1.1 Evidence of calculating the amount of **contingency reserve** as required in requirement R1.1 exists. Evidence may include records of the required and available **contingency reserve**.

MR1.2 Evidence of having **contingency reserve** that is comprised of the **operating reserve** types as required in requirement R1.2 exists. Evidence may include a **reserve sharing group** agreement including an agent appointment agreement or **ancillary services** contracts.

MR1.3 Evidence of having access to **contingency reserve** that is capable of fully responding in ten (10) minutes as required in requirement R1.3 exists. Evidence may include a **reserve sharing group** agreement including an agent appointment agreement or technical requirements for **contingency reserve**.

MR2 Evidence of maintaining at least fifty percent (50%) of the ISO's minimum amount of **contingency reserve** as **spinning reserve** that is immediately responsive to frequency deviations as required in requirement R2 exists. Evidence may include a **reserve sharing group** agreement including an agent appointment agreement or records of **dispatches** of **ancillary services**.

MR3 Evidence of maintaining an amount of **operating reserve** as required in requirement R3 exists. Evidence may include a sworn affidavit from an appropriate **ISO** representative, authoritative documents that restrict or permit the transactions set out in requirement R3, documents that demonstrate the **ISO** was in a capacity and energy emergency, or a **reserve sharing group** agreement including an agent appointment agreement.

MR4 Evidence of maintaining an amount of **operating reserve** as required in requirement R4 exists. Evidence may include a sworn affidavit from an appropriate **ISO** representative or a **reserve sharing group** agreement including an agent appointment agreement.

Revision History

Effective Date	Description
2015-07-26	Revised Applicability section to include exclusion for contingencies that result in the **interconnected electric system** losing synchronism with the **western interconnection**
2014-10-01	Initial release.

BAL-003-AB-0a Frequency Response and Bias

1. Purpose

The purpose of this *reliability standard* is to provide a consistent method for calculating the f*requency bias* component of *ACE*.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must review its *frequency bias settings* by January 1 of each year, and recalculate its setting to reflect any change in the *frequency response* of the *AIES*.

R1.1. The *ISO* may change its *frequency bias setting* and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.

R1.2. The *ISO* must report its *frequency bias setting* and method for determining that setting, to the *NERC* Operating Committee.

R2 The *ISO* must establish and maintain a *frequency bias setting* that is as close to practical or greater than the *AIES*'s *frequency response*. *Frequency bias* may be calculated in several ways:

R2.1. The *ISO* may use a fixed *frequency bias* value that is based on a fixed, straight-line function of *tie line* deviation or *tie line* trip event measurements versus *frequency deviation*. The *ISO* must determine the fixed value by observing and averaging the *frequency response* for several *disturbances*.

R2.2. The *ISO* may use a variable (linear or non-linear) *frequency bias* value that is based on a variable function of t*ie line* deviation, or *tie line* trip event measurements to *frequency deviation*. The *ISO* must determine the variable *frequency bias* value by analyzing *frequency response* as it varies with factors such as *load*, generation, governor characteristics, and frequency.

R3 The *ISO* must operate its *automatic generation control* (*AGC)* on *tie line frequency bias*, unless such operation is adverse to system or *Interconnection* reliability.

R4 The *ISO* must have a monthly average *frequency bias setting* that is at least 1% of the *AIES's* estimated yearly peak demand per 0.1 Hz change.

5. Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Documentation exists to show that a review was carried out according to R1.

MR1.2 Confirmation that *frequency bias setting* and methods have been submitted to *NERC* (*NERC* survey or e-mail submission is sufficient).

MR2 The *frequency bias setting* is close to or greater than the *AIES's* frequency response. The *frequency response* data is available for events analysis.

MR3 Energy Management System (EMS) records, which set *AGC* control modes of operation, are available to support R3.

MR4 A monthly average *frequency bias setting* and estimated yearly peak demand is available to support R4.

7. Appendices

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date	Description
2009-02-13	New Issue

Alberta Reliability Standard
Automatic Time Error Correction
BAL-004-WECC-AB-2

1. Purpose

The purpose of this **reliability standard** is to maintain the frequency of the **western interconnection** and to ensure that **time error corrections** and **primary inadvertent interchange** payback are effectively conducted in a manner that does not adversely affect the **reliability** of the **western interconnection**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 Following the conclusion of each **month**, the **ISO** must verify that the absolute value of its accumulated **primary inadvertent interchange** for both the monthly **on peak** period and the monthly **off peak** period are each individually less than or equal to 150% of the previous calendar year's peak demand, where peak demand is the highest hourly integrated **net energy for load**.

R2 The **ISO** must, within ninety (90) days of discovery of an error in the calculation of hourly **primary inadvertent interchange**, recalculate the value of hourly **primary inadvertent interchange** and adjust the accumulated **primary inadvertent interchange** from the time of the error.

R3 The **ISO** must, while synchronously connected to the **western interconnection**, keep its **automatic time error correction** in service, with an allowable exception period of less than or equal to an accumulated twenty-four (24) hours per calendar quarter for **automatic time error correction** to be out of service.

R3.1 Notwithstanding requirement R3, the **ISO** may disable automatic **time error correction** if there is a **reliability** concern on the **interconnected electric system** while executing an automatic **time error correction**, and this time will not be included as part of the allowable exception period.

R4 The **ISO** must compute the following by fifty (50) minutes after each hour:

R4.1 the hourly **primary inadvertent interchange**;

R4.2 the accumulated **primary inadvertent interchange**; and

R4.3 the **automatic time error correction** term.

R5 The **ISO** must be able to change its **automatic generation control** operating mode between flat frequency, flat tie line, tie line bias, and tie line bias plus **time error** control, to correspond to current operating conditions.

R6 The **ISO** must recalculate the hourly **primary inadvertent interchange** and accumulated **primary inadvertent interchange** for the **on peak** and **off peak** periods whenever adjustments are made to hourly **inadvertent interchange** or the hourly change in system **time error**, as distributed by the **Interconnection** time monitor.

R7 The **ISO** must make the same adjustment to the accumulated **primary inadvertent interchange** as it did for any **month**-end meter reading adjustments to **inadvertent interchange**.

R8 The **ISO** must payback **inadvertent interchange** using **automatic time error correction** rather than bilateral and unilateral payback.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence of verifying the absolute value of the **ISO**'s accumulated **primary inadvertent interchange** as required in requirement R1 exists. Evidence may include, but is not limited to, data, screen shots from the **WECC** Interchange Tool, production of data from any other databases, spreadsheets, displays, or other equivalent evidence.

MR2 Evidence of recalculating the value of hourly **primary inadvertent interchange** and adjusting the accumulated **primary inadvertent interchange** from the time of the error as required in requirement R2 exists. Evidence may include, but is not limited to, data, screen shots from the **WECC** Interchange Tool, production data from any other databases, spreadsheets, displays, or other equivalent evidence.

MR3 Evidence of keeping the **automatic time error correction** in service as required in requirement R3 exists. Evidence may include, but is not limited to, dated archived files, historical data, or other equivalent evidence.

MR4 Evidence of computing the hourly **primary inadvertent interchange**, accumulated **primary inadvertent interchange** and **automatic time error correction** as required in requirement R4 exists. Evidence may include, but is not limited to, data, screen shots from the **WECC** Interchange Tool, data from any other databases, spreadsheets, displays, or other equivalent evidence.

MR5 Evidence of having the ability to change the **automatic generation control** operating mode as required in requirement R5 exists. Evidence may include, but is not limited to, snapshots of the operating interface provided in the energy management system for changing its **automatic generation control** operating mode, or other equivalent evidence.

MR6 Evidence of recalculating hourly **primary inadvertent interchange** and accumulated **primary inadvertent interchange** as required in requirement R6 exists. Evidence may include, but is not limited to, data, screen shots from the **WECC** Interchange Tool, data from any other databases, spreadsheets, displays, or other equivalent evidence.

MR7 Evidence of making the adjustments to accumulated **primary inadvertent interchange** as required in requirement R7 exists. Evidence may include, but is not limited to, data, screen shots of the **WECC** Interchange Tool, data from any other databases, spreadsheets, displays, or other equivalent evidence.

MR8 Evidence of paying back the **inadvertent interchange** as required in requirement R8 exists. Evidence may include, but is not limited to, historical **inadvertent interchange** data, data from the **WECC** Interchange Tool, or other equivalent evidence.

Revision History

Date	Description
2016-12-19	Initial release.

Alberta Reliability Standard
Automatic Generation Control
BAL-005-AB3-0.2b

1. Purpose

The purpose of this **reliability standard** is to establish the necessary related requirements for the **ISO**'s **automatic generation control**.

2. Applicability

This **reliability standard** applies to:

(a) the **legal owner** of a **transmission facility** that provides frequency or **intertie** metering data the **ISO** uses for **automatic generation control**, which such frequency or **intertie** metering data is collected from the source the **ISO** identifies and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;

(b) the **legal owner** of a **generating unit** that provides frequency data the **ISO** uses for **automatic generation control**, which such frequency data is collected from the source the **ISO** identifies and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1; and

(c) the **ISO**.

3. Requirements

R1 Intentionally left blank.

R2 Intentionally left blank.

R3 The **ISO** must, when providing regulation service, have adequate metering, communications, and control equipment employed to prevent such regulation service from becoming a burden on the **interconnection** or other **balancing authority areas**.

R4 The **ISO** must, when providing regulation service, notify the host **balancing authority** for which it is providing regulating service if it is unable to provide the regulation service and must also notify any intermediate **balancing authorities**.

R5 The **ISO** must, when receiving regulation service, have backup plans in place to provide replacement regulation service should the supplying **balancing authority** no longer be able to provide this service.

R6 The **ISO** must include the calculation of **area control error**, which compares total **net actual interchange** to total **net scheduled interchange** plus **frequency bias** obligation, in the design of its **automatic generation control**, except that the **ISO** may include an alternative calculation of **area control error** in the design of its **automatic generation control** for periods in which the **ISO** operates the **interconnected electric system** asynchronously.

R7 Subject to requirement R7.1, the **ISO** must operate its **automatic generation control** continuously.

R7.1 The **ISO** must, if **automatic generation control** has become inoperative or operation of **automatic generation control** could adversely impact the reliability of the **interconnection**, use manual controls to adjust generation to maintain the **net scheduled interchange**.

R8 The **ISO** must use a design scan rate of no more than nine (9) seconds in acquiring data necessary to calculate **area control error**.

R8.1 The **ISO** must use frequency data from redundant and independent frequency metering equipment that automatically activates upon detection of failure of the primary source; and

R8.2 The **ISO** must provide frequency metering data to its **automatic generation control** with a minimum availability of 99.95%.

R9 Subject to requirement R9.1, the **ISO** must include all **interchange schedules** with **adjacent balancing authorities** in the **ISO**'s calculation of **net scheduled interchange** for the **area control error** calculation.

R9.1 The **ISO** may omit the **interchange schedule** for a high voltage direct current link to another **balancing authority** from the **area control error** calculation if such **interchange schedule** is modeled by the **ISO** as internal generation or load.

R10 The **ISO** must include all dynamic schedules in the calculation of **net scheduled interchange** for the **area control error** calculation.

R11 The **ISO** must include the effect of ramp rates, which must be identical and agreed to between affected **balancing authorities**, in the scheduled **interchange** values to calculate the **area control error**.

R12 The **ISO** must include all **interconnection** flows of **real power** in the **area control error** calculation, except those flows that are excluded by the application of requirement R9.1.

R12.1 The **ISO** must use MW metering data for each **interconnection** that:

(a) emanates from a common, agreed-upon source using common primary metering equipment; and

(b) is telemetered to its system coordination centre and the control centre of the **adjacent balancing authority**;

R12.2 The **legal owner** of a **transmission facility** must not filter:

(a) MW metering data for **interconnections**; or

(b) **area control error** signals transmitted to the **ISO**, except for the anti-aliasing filters of **interconnections**;

R12.3 The **ISO** must use unfiltered:

(a) MW metering data for **interconnections**; or

(b) **area control error** signals;

provided by the **legal owner** of a **transmission facility** for calculating the **ISO**'s performance under the **control performance standard**, except for the anti-aliasing filters of **interconnections**; and

R12.4 The **ISO** must ensure that common metering equipment is installed where dynamic schedules or pseudo-ties are implemented between two (2) or more **balancing authorities** to deliver the output of jointly owned **generating units** or to serve remote load.

R13 The **ISO** must perform hourly error checks using **intertie** MWh meters with common time synchronization to determine the accuracy of its control equipment.

The **ISO** must adjust the component of the **area control error** that is in error, if known, or use the interchange meter error (I_{ME}) term of the **area control error** equation, to compensate for any metering equipment error until repairs can be made.

R14 The **ISO** must provide its operating personnel with real-time values for the **area control error**, **interconnection** frequency and **net actual interchange** with each **adjacent balancing authority**.

The **ISO** must provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate the monitoring of the **control performance standard**, generation response and after-the-fact analysis of area performance.

R15 The **ISO** must have adequate and reliable backup power supplies at the **ISO**'s system coordination centre and at the **ISO**'s backup system coordination centre, which must be periodically tested, to maintain continuous operation of the **automatic generation control** and vital data recording equipment during loss of the normal power supply.

R16 The **ISO** must:

(a) sample **area control error**-related data at least at the same periodicity with which the **area control error** is calculated;

(b) flag missing or bad **area control error**-related data for **operator** display and archival purposes; and

(c) collect coincident **area control error**-related data to the greatest extent practical.

R17 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit**, and the **ISO** must:

(a) check and calibrate its digital frequency transducer used for **automatic generation control** against a common reference, at least once every calendar year;

but if these transducers cannot be calibrated,

(b) cross-check its digital frequency transducer used for **automatic generation control** against at least two (2) other frequency transducers or pieces of equipment, calibrated by the manufacturer, at least once every calendar year; and

(c) replace any digital frequency transducer that is not accurate to within 0.001 Hz.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Intentionally left blank.

MR2 Intentionally left blank.

MR3 Evidence of having adequate metering, communications, and control equipment employed as required in requirement R3 exists. Evidence may include, but is not limited to, regulation service agreements or other documentation confirming that metering, communications and control equipment employed are adequate to prevent such service from becoming a burden.

MR4 Evidence of notifying the host **balancing authority** and any intermediate **balancing authorities** as required in requirement R4 exists. Evidence may include, but is not limited to, voice recordings or **operator** logs.

MR5 Evidence of having backup plans in place as required in requirement R5 exists. Evidence may include, but is not limited to, a dated and in effect backup plan(s).

MR6 Evidence of including **area control error** calculations in the design of the **automatic generation control** of the **ISO** as required in requirement R6 exists. Evidence may include, but is not limited to, the algorithm or code for **automatic generation control** that show the calculation of the **area control error** is included in the design of the **automatic generation control** of the **ISO** or other equivalent evidence.

MR7 Evidence of operating **automatic generation control** continuously as required in requirement R7 exists. Evidence may include, but is not limited to:

(a) data files showing the **automatic generation control** was operated continuously;

(b) where the **automatic generation control** was not operated continuously documentation of the rationale of not operating **automatic generation control** continuously; and

(c) **operator** logs and voice recordings.

MR7.1 Evidence of using manual controls to adjust generation as required in requirement R7.1 exists. Evidence may include, but is not limited to, operator logs or voice recordings.

MR8 Evidence of using a design scan rate of no more than nine (9) seconds in acquiring data necessary to calculate **area control error** as required in requirement R8 exists. Evidence may include, but is not limited to, documentation of data acquisition rate or other equivalent evidence.

MR8.1 Evidence of using frequency data as required in requirement R8.1 exists. Evidence may include, but is not limited to, a list of independent and redundant frequency metering equipment.

MR8.2 Evidence of providing frequency metering data as required in requirement R8.2 exists. Evidence may include, but is not limited to, records of frequency metering data availability to its **automatic generation control**.

MR9 Evidence of including all **interchange schedules** with **adjacent balancing authorities** in the **ISO**'s calculation as required in requirement R9 exists. Evidence may include, but is not limited to, the algorithm or codes of the calculation of the **area control error**.

MR9.1 Evidence of omitting the **interchange schedule** for a high voltage direct current link as allowed in requirement R9.1 exists. Evidence may include, but is not limited to, modeling data documentation showing that the omitted **interchange schedule** for a high voltage direct current link was modeled as internal generation or load.

MR10 Evidence of including dynamic schedules in the calculation of **net scheduled interchange** as required in requirement R10 exists. Evidence may include, but is not limited to, modeling data documentation showing dynamic schedules, if they exist, are included in the **area control error** equation.

MR11 Evidence of including the effect of ramp rates in the scheduled **interchange** values as required in requirement R11 exists. Evidence may include, but is not limited to:

(a) documentation showing the effect of ramp rates was included in the calculation of the **area control error**; and

(b) documentation showing the ramp rates were identical and agreed to between affected **balancing authorities**.

MR12 Evidence of including all **interconnection** flows of **real power** in the calculation as required in requirement R12 exists. Evidence may include, but is not limited to, the algorithm or codes of the calculation of the **area control error**.

MR12.1 Evidence of using MW metering data for **interconnections** as required in requirement R12.1 exists. Evidence may include, but is not limited to, measurement definition records and documentation showing the agreement on the source and metering equipment with the **adjacent balancing authority**.

MR12.2 Evidence of not filtering metering data or **area control error** signals as required in requirement R12.2 exists. Evidence may include, but is not limited to, data files showing that the MW metering data for **interconnections** or **area control error** signals transmitted to the **ISO** are not filtered prior to transmission.

MR12.3 Evidence of using unfiltered metering data or **area control error** signals as required in requirement R12.3 exists. Evidence may include, but is not limited to, data files showing that the unfiltered data received by the **ISO** is the same data used in the **area control error** calculation.

MR12.4 Evidence of ensuring that common metering equipment is installed as required in requirement R12.4 exists. Evidence may include, but is not limited to, documentation showing the agreement on the common metering equipment with the other **balancing authority**.

MR13 Evidence of performing MWh hourly error checks as required in requirement R13 exists. Evidence may include, but is not limited to, records of hourly error checks and records of adjustments made for each discrepancy, if any, identified in the hourly error checks.

Evidence of adjusting the component of the **area control error** that is in error as required in requirement R13 exists. Evidence may include, but is not limited to, files or data showing the error was included in the **area control error**.

MR14 Evidence of providing real-time values for **area control error**, **interconnection** frequency and **net actual interchange**, as required in requirement R14 exists. Evidence may include, but is not limited to, screen shots of the interface displaying the real-time data.

Evidence of providing sufficient instrumentation and data recording equipment as required in requirement R14 exists. Evidence may include, but is not limited to, a list of instrumentation, data and recording equipment and screen shots of the interface displaying the **control performance standard**, generation response and after-the-fact analysis of area performance.

MR15 Evidence of having adequate and reliable backup power supplies and of periodically testing these supplies as required in requirement R15 exists. Evidence may include, but is not limited to, a list of backup power supplies, a periodic testing plan for these backup power supplies and records of the tests.

MR16 Evidence of sampling, flagging and collecting **area control error**-related data as required in requirement R16 exists. Evidence may include, but is not limited to:

(a) algorithms of the sampling **area control error**-related data;

(b) screenshots of the **operator** display;

(c) archived files for missing or bad **area control error** related data; and

(d) archived files for coincident **area control error** data.

MR17 Evidence of checking, calibrating and replacing digital frequency transducers as required in requirement R17 exists. Evidence may include, but is not limited to:

(a) a list of digital frequency transducers used for **automatic generation control**;

(b) records, including the dates and measured accuracy values, of checking and calibrating against a common reference;

(c) where the manufacturer's specification does not require calibration of these digital frequency transducers or these digital transducers cannot be calibrated, evidence to substantiate this

and records showing the dates of cross-checking against other frequency transducers or pieces of equipment and the accuracy values of these devices.

5. Appendices

Appendix 1 – *Amending Process for List of Frequency Data and Intertie Metering Data*

Revision History

Date	Description
2017-06-12	Intial release

Appendix 1

Amending Process for List of Frequency Data and Intertie Metering Data

In order to amend the lists referenced in subsections (a) and (b) of section 2, *Applicability*, the **ISO** must:

(a) upon determining that a source of frequency or **intertie** metering data is to be added to the list, notify each affected **legal owner** of a **generating unit** or **legal owner** of a **transmission facility** in writing and determine an effective date, which must be no less than thirty (30) **days** after the date of notice, for the **legal owner** to meet the applicable requirements;

(b) upon determining that a source of frequency or **intertie** metering data is to be deleted, notify each affected **legal owner** of a **generating unit** or **legal owner** of a **transmission facility** in writing and determine an effective date for the **legal owner** to no longer be required to meet the applicable requirements; and

(c) post the amended list with effective dates on the AESO website.

BAL-006-AB-1 Inadvertent Interchange

1. Purpose

The purpose of this *reliability standard* is to define a process for monitoring the *ISO* to ensure that, over the long term, the *AIES* does not excessively depend on other *balancing authority areas* in the *WECC* for meeting its demand or *interchange* obligations.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must calculate and record hourly *inadvertent interchange*.

R2 The *ISO* must include all *AC tie lines* that connect to the *AIES's* adjacent *balancing authority areas* in the *AIES's inadvertent interchange* account.

R3 The *ISO* must ensure all of the *AIES's* interconnection points are equipped with common megawatt hour meters, with readings provided hourly to the control centers of adjacent *balancing authorities*.

R4 The *ISO* must operate to a common *net interchange schedule* and *net actual interchange* value with its adjacent *balancing authority areas,* and must record these hourly quantities, with like values but opposite sign with the adjacent *balancing authority areas*. The *ISO* must calculate its *inadvertent interchange* based on the following:

R4.1 Subject to R5, the *ISO* must agree with its adjacent *balancing authorities* to:

R4.1.1 The hourly values of *net interchange schedule*.

R4.1.2 The hourly integrated megawatt hour values of *net actual interchange*.

R4.2. The *ISO* must use the agreed upon daily and monthly accounting data to compile its monthly accumulated *inadvertent interchange* for the *on-peak* and *off-peak* hours of the *month*.

R4.3 The *ISO* must make after-the-fact corrections to the agreed upon daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data).

Changes or corrections based on non-reliability considerations must not be reflected in the *AIES's inadvertent interchange*. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the *adjacent balancing authority(ies*).

R5 If the *ISO* cannot mutually agree with its *adjacent balancing authorities* on the respective *net actual interchange* or *net scheduled interchange* quantities by the 15th calendar *day* of the following *month*, the *ISO* must, for the purposes of dispute resolution, submit a report to the *WECC* Survey Contact with information describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.

5. Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following *measures* correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 *Inadvertent interchange* records are complete and accurate.

MR2 Records include the applicable *AC tie lines*.

MR3 Documents such as metering records or schematics identifying meters in place at these points, exist or are provided.

MR4 *Net interchange schedule* exists, is complete for all hours and applicable *AC tie lines*, and corresponds with the adjacent area values.

MR4.1.1 Evidence indicating agreement exists for all hourly values of the *net interchange schedule.*

MR4.1.2 Evidence indicating that agreement exists for all hourly integrated megawatt hour values of net actual interchange.

MR4.2 Evidence indicating that accounting data corresponds with data from *net interchange schedules* as well as *net actual interchanges*.

MR5 Dispute documents follow the specified process and timing.

7. Appendices

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date	Description
2009-02-13	New Issue

Alberta Reliability Standard
Cyber Security – Supplemental CIP Alberta Reliability Standard
CIP-SUPP-001-AB1

A. Introduction

1. Title: Cyber Security – Supplemental CIP Alberta Reliability Standard
2. Number: CIP-SUPP-001-AB1
3. Purpose: The purpose of this **reliability standard** is to allow the **ISO** to approve variances to the requirements of a CIP Cyber Security **reliability standard**, other than **technical feasibility exceptions**.
4. Applicability:

   This **reliability standard** applies to those Responsible Entities listed in CIP-002-AB-5.1, *Cyber Security – BES Cyber System Categorization*, section 4, Applicability.

B. Requirements and Measures

R1 A Responsible Entity, other than the **ISO**, must, where it seeks a variance to the requirements of a CIP Cyber Security **reliability standard**, make a request in writing to the **ISO** outlining (i) the requirements of the particular CIP Cyber Security **reliability standard** in respect of which the variance is sought; (ii) the grounds in support of the requested variance, which grounds must not be frivolous or of little merit; and (iii) the requested effective dates of the variance.

M1 Evidence of a request for a variance being made in writing as required in requirement R1 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request.

R2 The **ISO** and the Responsible Entity must treat a request for a variance under requirement R1, all records related to such a request, and a variance approved under requirement R3, as confidential in accordance with the provisions of section 103.1 of the ISO rules, *Confidentiality*, provided however that where the request for a variance is made by a Responsible Entity whose rights and obligations are the subject of a power purchase arrangement that Responsible Entity may disclose to its counterparties such information in respect of the variance as and if required under the terms of the power purchase arrangement.

R2.1 Where the **ISO** determines that the disclosure of a request for a variance under requirement R1, all records related to such a request, or a variance approved under requirement R3:

(a) would have no material impact on the **reliability** of the interconnected electric system; and

(b) does not contain information which, in the opinion of the **ISO**, is commercially sensitive,

requirement R2 of this standard does not apply and the **ISO** may publicly disclose the request and all records related to the request in accordance with subsection 2(6)(b)(i) of section 103.1 of the **ISO rules**.

M2 Evidence of treating the request as confidential as described in requirement R2 exists, unless requirement R2.1 applies.

R3 The **ISO** must, where it approves a variance requested under requirement R1:

(a) indicate the effective dates of the variance;

(b) identify the Responsible Entity to which the variance applies;

(c) maintain a copy of the variance, in writing; and

(d) provide a copy of the variance, in writing, to the Responsible Entity that has requested the variance.

M3 Evidence of taking the steps required in requirement R3 exists. Evidence may include, but is not limited to, a written copy of the variance including its effective dates, correspondence to the Responsible Entity enclosing a copy of the variance or other equivalent evidence.

R4 The **ISO** must not, in any event, approve a variance requested under requirement R1 unless the **ISO** determines, by its own assessment, that the variance has merit and will not have a material impact on the **reliability** of the **interconnected electric system**.

M4 Evidence of performing an assessment in accordance with requirement R4 exists. Evidence may include, but is not limited to, a copy of the **ISO**'s business practices relating to variances of a CIP Cyber Security **reliability standard**.

R5 The **ISO** must, where it does not approve a variance requested under requirement R1, provide a copy of its decision, including reasons, in writing, to the Responsible Entity that has requested the variance.

M5 Evidence of issuing a decision denying the variance requested exists. Evidence may include, but is not limited to, a hard copy or electronic copy of a letter from the **ISO** denying the variance requested.

R6 Notwithstanding any of the requirements of this **reliability standard**, a Responsible Entity must make a request for a **technical feasibility exception** in accordance with the provisions of CIP-SUPP-002-AB, *Technical Feasibility Exceptions*.

M6 Evidence of requesting a **technical feasibility exception** as required in requirement R6 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request, or other equivalent evidence.

Revision History

Date	Description
2017-03-21	Addition of requirement R6 and associated measure. Revision to purpose statement.
2015-06-05	Initial release.

Alberta Reliability Standard
Cyber Security – Supplemental CIP Alberta Reliability Standard Technical Feasibility Exceptions
CIP-SUPP-002-AB

A. Introduction

1. Title: Cyber Security – Supplemental CIP Alberta Reliability Standard Technical Feasibility Exceptions
2. Number: CIP-SUPP-002-AB
3. Purpose: The purpose of this **reliability standard** is to allow the **ISO** to approve **technical feasibility exceptions** to the requirements of a CIP Cyber Security **reliability standard**.
4. Applicability:

   This **reliability standard** applies to those Responsible Entities listed in CIP-002-AB-5.1, *Cyber Security – BES Cyber System Categorization,* section 4, Applicability.

B. Requirements and Measures

R1 A Responsible Entity other than the **ISO** must, where:

(a) a requirement in the CIP Cyber Security **reliability standards** uses the phrase "where technically feasible"; and

(b) the Responsible Entity seeks a variance from the requirement referenced in sub-requirement R1(a) on the grounds of technical feasibility,

request that the **ISO** approve a **technical feasibility exception**.

MR1 Evidence of a request for a **technical feasibility exception** as required in requirement R1 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request, or other equivalent evidence.

R2 A Responsible Entity must make a request under requirement R1 in writing in the form specified by the **ISO**.

MR2 Evidence of making a request in writing as described in requirement R1 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request, or other equivalent evidence.

R3 At the **ISO**'s request, a Responsible Entity must provide:

(a) any additional information relating to a request for a **technical feasibility exception**; or

(b) the reasons why the additional information will not be provided.

MR3 Evidence of providing additional information or reasons in accordance with requirement R3 exists. Evidence may include, but is not limited to, a hard copy or electronic copy of the request and the response, or other equivalent evidence.

R4 The **ISO** and the Responsible Entity must treat a request for a **technical feasibility exception** under requirement R1, and all records related to such a request, as confidential in accordance with the provisions of section 103.1 of the ISO rules, *Confidentiality*, provided however that where the request for a **technical feasibility exception** is made by a Responsible Entity whose rights and obligations are the subject of a power purchase arrangement, that Responsible Entity may disclose to its counterparties such information in respect of the **technical feasibility exception** as and if required under the terms of the power purchase arrangement.

MR4 Evidence of treating the request as confidential as described in requirement R4 exists.

R5 The **ISO** must post the criteria that it considers when determining whether to approve or disapprove a request for a **technical feasibility exception** on the AESO website, and must notify Responsible Entities at least thirty (30) **days** in advance of any amendments to the criteria.

MR5 Evidence of posting the criteria and notifying Responsible Entities as described in requirement R5 exists. Evidence may include, but is not limited to, a dated copy of the AESO website posting and a dated posting in the AESO stakeholder newsletter.

R6 The **ISO** must, upon reviewing a Responsible Entity's request submitted under requirement R1 and any additional information provided to the **ISO**, approve the request in whole or in part, or disapprove the request.

R6.1 The **ISO** must, where the request submitted under requirement R1 is approved, provide a copy of its decision, in writing, to the Responsible Entity that has requested the **technical feasibility exception** and set out:

(a) any terms and conditions of the approval; and

(b) the expiration date of the approval.

R6.2 The **ISO** must, where the request submitted under requirement R1 is disapproved, provide a copy of its decision, including reasons, in writing, to the Responsible Entity that has requested the **technical feasibility exception**.

MR6 Evidence of an approval or disapproval of the request as described in requirement R6 exists. Evidence may include but is not limited to a dated copy of the approval or disapproval.

R7 A Responsible Entity must, where there is a material change in the facts underlying the request for or approval of a **technical feasibility exception**, submit a revised request to the **ISO** under requirement R2 within sixty (60) **days** of becoming aware of the material change.

MR7 Evidence of submitting a revised request to the **ISO** in accordance with requirement R7 exists. Evidence may include, but is not limited to, a dated record of becoming aware of a material change in facts and a dated hard copy or electronic copy of the revised request, or other equivalent evidence.

R8 The **ISO** may, after providing written notice to the Responsible Entity, amend or terminate a **technical feasibility exception** prior to the expiration date of the **technical feasibility exception** where:

(a) a Responsible Entity does not fulfill the terms and conditions of the approval;

(b) there is a material change in the facts underlying the approval; or

(c) the Responsible Entity advises the **ISO**, in writing, that the **technical feasibility exception** is no longer required.

MR8 Evidence of amending or terminating a **technical feasibility exception** and providing notice prior to the expiration date of the approval as described in requirement R8 exists. Evidence may include, but is not limited to, a dated hard copy or electronic copy of the amended or terminated **technical feasibility exception** provided to the Responsible Entity.

Revision History

Date	Description
2017-03-21	Initial release.

Alberta Reliability Standard
Cyber Security – BES Cyber System Categorization
CIP-002-AB-5.1

A. Introduction

1. Title: Cyber Security – BES Cyber System Categorization

2. Number: CIP-002-AB-5.1

3. Purpose: To identify and categorize **BES cyber systems** and their associated **BES cyber assets** for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those **BES cyber systems** could have on the reliable operation of the **bulk electric system**. Identification and categorization of **BES cyber systems** support appropriate protection against compromises that could lead to misoperation or instability in the **bulk electric system**.

4. Applicability:

   4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

      4.1.1. [Intentionally left blank.]

      4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

         4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

            4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

            4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

         4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

         4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

         4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

      4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

      4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

      4.1.5. [Intentionally left blank.]

4.1.6. [Intentionally left blank.]

4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

5. [Intentionally left blank.]
6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

(i) **control centres** and backup **control centres**;

(ii) transmission stations and substations;

(iii) **generating units** and **aggregated generating facilities**;

(iv) systems and facilities critical to system restoration, including contracted **blackstart resources** and **cranking paths** and initial switching requirements;

(v) **remedial action schemes** that support the reliable operation of the **bulk electric system**; and

(vi) for the **legal owner** of an **electric distribution system** or **legal owner** of a **transmission facility**, **protection systems** specified in Applicability subsection 4.2.1 above.

1.1. Identify each of the high impact **BES cyber systems** according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact **BES cyber systems** according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact **BES cyber system** according to Attachment 1, Section 3, if any (a discrete list of low impact **BES cyber systems** is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall:

2.1. review the identifications in requirement R1 and its parts (and update them if there are changes identified) at least once every 15 **months**, even if it has no identified items in requirement R1, and

2.2. have its **CIP senior manager** or delegate approve the identifications required by requirement R1 at least once every 15 **months**, even if it has no identified items in requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in requirement R1 and its parts, and has had its **CIP senior manager** or delegate approve the identifications required in requirement R1 and its parts at least once every 15 **months**, even if it has none identified in requirement R1 and its parts, as required by requirement R2.

Attachments

Attachment 1 – *Impact Rating Criteria*

Revision History

Date	Description
2017-10-01	Initial release.

CIP-002-AB-5.1 Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each **BES cyber system** used by and located at any of the following:

1.1. the **ISO**'s **control centre** and backup **control centre**;

1.2. [Intentionally left blank.]

1.3. each **control centre** or backup **control centre** used to perform the functional obligations of an **operator** of a **transmission facility** for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.8, 2.9, or 2.10; and

1.4. each **control centre** or backup **control centre** used to perform the functional obligations of the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** for one or more of the assets that meet criterion 2.1, 2.3, 2.6, 2.8, or 2.9.

2. Medium Impact Rating (M)

Each **BES cyber system**, not included in Section 1 above, associated with any of the following:

2.1. commissioned generation, by each group of **generating units** or **aggregated generating facilities** at a single plant location, with an aggregate **maximum authorized real power** rating of each of the generating units minus the station service load equal to or exceeding 1500 MW in a single **Interconnection**. For each group of **generating units** or **aggregated generating facilities**, the only **BES cyber systems** that meet this criterion are those shared **BES cyber systems** that could, within 15 minutes, adversely impact the reliable operation of any combination of **generating units** and/or **aggregated generating facilities** that in aggregate equal or exceed 1500 MW in a single **Interconnection**;

2.2. each **bulk electric system** reactive resource or group of resources at a single location (excluding **generating units** and **aggregated generating facilities**) with an aggregate maximum **reactive power** nameplate rating of 1000 MVAR or greater(excluding those at generating units or aggregated generating facilities). The only **BES cyber systems** that meet this criterion are those shared **BES cyber systems** that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR;

2.3. each **generating unit** and **aggregated generating facility** that the **ISO** designates, and informs the **legal owner** of the **generating unit** or **legal owner** of the **aggregated generating facility**, as necessary to avoid an **adverse reliability impact** in the planning horizon of more than one year;

2.4. **transmission facilities** operated at 500 kV or higher;

2.5. **transmission facilities** that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing **bulk electric system** transmission line that is connected to another transmission station or substation;

Voltage Value of a Line	Weight Value per Line
Less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.6. **generating units** at a single plant location, **aggregated generating facilities** or **transmission facilities** at a single station or substation location that are identified by the **ISO** as critical to the derivation of **interconnection reliability operating limits** and their associated contingencies;

2.7. [Intentionally left blank.]

2.8. **transmission facilities** and switchyards associated with **generating units** or **aggregated generating facilities** that connect the generator output to the **transmission system** that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of a **generating unit** or an **aggregated generating facility** identified by any **legal owner** of a **generating unit** or any **legal owner** of an **aggregated generating facility** as a result of its application of Attachment 1, criterion 2.1 or 2.3;

2.9. each **remedial action scheme**, or automated switching system that operates **system element(s)** of the **bulk electric system**, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more **interconnection reliability operating limits** (**IROLs**) violations for failure to operate as designed or cause a reduction in one or more **IROLs** if destroyed, degraded, misused, or otherwise rendered unavailable;

2.10. each system or group of element(s) that performs automatic load shedding under a common control system, without human operator initiation, of 300 MW or more implementing **under voltage load shed** or **underfrequency load shedding** under a load shedding program that is subject to one or more requirements in a **reliability standard;**

2.11. each **control centre** or backup **control centre**, not already included in High Impact Rating (H) above, used to perform the functional obligations of the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** for an aggregate highest rated net **real power** capability of the preceding 12 **months** equal to or exceeding 1500 MW; and

2.12. each **control centre** or backup **control centre** used to perform the functional obligations of the **operator** of a **transmission facility** not included in High Impact Rating (H), above, with

the exception of the **operator** of a transmission facility whose only transmission facility is a radial connection from either a **generating unit**, **aggregated generating facility** or industrial complex to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat.

2.13. [Intentionally left blank.]

3. Low Impact Rating (L)

BES cyber systems not included in sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in subsection 4.2 of this **reliability standard**:

3.1. **control centres** and backup **control centres;**

3.2. transmission stations and substations;

3.3. **generating units** and **aggregated generating facilities**;

3.4. systems and facilities critical to system restoration, including contracted **blackstart resources** and **cranking paths** and initial switching requirements;

3.5 **remedial action schemes** that support the reliable operation of the **bulk electric system**; and

3.6. for a **legal owner** of an **electric distribution system** or **legal owner** of a **transmission facility**, **protection systems** specified in subsection 4.2.1 of this **reliability standard**.

Alberta Reliability Standard
Cyber Security – Security Management Controls
CIP-003-AB-5

A. Introduction

1. Title: Cyber Security – Security Management Controls

2. Number: CIP-003-AB-5

3. Purpose: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect **BES cyber systems** against compromise that could lead to misoperation or instability in the **bulk electric system**.

4. Applicability:

4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

4.1.1. [Intentionally left blank.]

4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

4.1.5. [Intentionally left blank.]

4.1.6. [Intentionally left blank.]

4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**

of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

5. [Intentionally left blank.]

6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity, for its High Impact and Medium Impact **BES cyber systems**, shall review and obtain **CIP senior manager** approval at least once every 15 **months** for one or more documented cyber security policies that collectively address the following topics:

1.1 Personnel & training (CIP-004-AB-5.1);

1.2 Electronic security perimeters (CIP-005-AB-5) including **interactive remote access**;

1.3 Physical security of **BES cyber systems** (CIP-006-AB-5);

1.4 System security management (CIP-007-AB-5);

1.5 Incident reporting and response planning (CIP-008-AB-5);

1.6 Recovery plans for **BES cyber systems** (CIP-009-AB-5);

1.7 Configuration change management and vulnerability assessments (CIP-010-AB-1);

1.8 Information protection (CIP-011-AB-1); and

1.9 Declaring and responding to **CIP exceptional circumstances**.

M1. Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 **months**; and documented approval by the **CIP senior manager** for each cyber security policy.

R2. Each Responsible Entity for its assets identified in CIP-002-AB-5.1, requirement R1, part 1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain **CIP senior manager** approval for those policies at least once every 15 **months**:

2.1 Cyber security awareness;

2.2 Physical security controls;

2.3 Electronic access controls for external routable protocol connections and **dial-up connectivity**; and

2.4 Incident response to a **cyber security incident**.

An inventory, list, or discrete identification of Low Impact **BES cyber systems** or their **BES cyber assets** is not required.

M2. Examples of evidence may include, but are not limited to, one or more documented cyber security policies and evidence of processes, procedures, or plans that demonstrate the implementation of the required topics; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 **months**; and documented approval by the **CIP senior manager** for each cyber security policy.

R3. Each Responsible Entity shall identify a **CIP senior manager** by name and document any change within 30 **days** of the change.

M3. An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the **CIP senior manager**.

R4. The Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP **reliability standards**, the **CIP senior manager** may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the **CIP senior manager**; and updated within 30 **days** of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator.

M4. An example of evidence may include, but is not limited to, a dated document, approved by the **CIP senior manager**, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – Personnel & Training
CIP-004-AB-5.1

A. Introduction

1. Title: Cyber Security – Personnel & Training

2. Number: CIP-004-AB-5.1

3. Purpose: To minimize the risk against compromise that could lead to misoperation or instability in the **bulk electric system** from individuals accessing **BES cyber systems** by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting **BES cyber systems**.

4. Applicability:

4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

4.1.1. [Intentionally left blank.]

4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

4.1.5. [Intentionally left blank.]

4.1.6. [Intentionally left blank.]

4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated**

generating facilities that have a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized

as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes.

5. [Intentionally left blank.]

6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R1 – Security Awareness Program.*

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R1 – Security Awareness Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-AB-5.1 Table R1 – Security Awareness Program

Part	Applicable Systems	Requirements	Measures
1.1	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	Security awareness that, at least once each calendar quarter, reinforces cyber security practices (which may include associated physical security practices) for the Responsible Entity's personnel who have authorized electronic or authorized unescorted physical access to **BES cyber systems**.	An example of evidence may include, but is not limited to, documentation that the quarterly reinforcement has been provided. Examples of evidence of reinforcement may include, but are not limited to, dated copies of information used to reinforce security awareness, as well as evidence of distribution, such as: • direct communications (for example, e-mails, memos, computer-based training); or • indirect communications (for example, posters, intranet, or brochures); or • management support and reinforcement (for example, presentations or meetings).

R2. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-AB-*

5.1 Table R2 – Cyber Security Training Program.

M2. Evidence must include the training program that includes each of the applicable requirement parts in *CIP-004-AB-5.1 Table R2 – Cyber Security Training Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-AB-5.1 Table R2 – Cyber Security Training Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	Training content on: 2.1.1. cyber security policies; 2.1.2. physical access controls; 2.1.3. electronic access controls; 2.1.4. the visitor control program; 2.1.5. handling of **BES cyber system information** and its storage; 2.1.6. identification of a **cyber security incident** and initial notifications in accordance with the entity's incident response plan; 2.1.7. recovery plans for **BES cyber systems**; 2.1.8. response to **cyber security incidents**; and 2.1.9. cyber security risks associated with a **BES cyber system**'s electronic interconnectivity and interoperability with other **cyber assets**.	Examples of evidence may include, but are not limited to, training material such as power point presentations, instructor notes, student notes, handouts, or other training materials.
2.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and	Require completion of the training specified in part 2.1 prior to granting authorized electronic access and authorized unescorted physical access to applicable	Examples of evidence may include, but are not limited to, training records and documentation of when **CIP exceptional circumstances** were invoked.

CIP-004-AB-5.1 Table R2 – Cyber Security Training Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
	2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	**cyber assets**, except during **CIP exceptional circumstances**.	
2.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	Require completion of the training specified in part 2.1 at least once every 15 **months**.	Examples of evidence may include, but are not limited to, dated individual training records.

R3. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented personnel risk assessment programs to attain and retain authorized electronic or authorized unescorted physical access to **BES Cyber Systems** that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R3 – Personnel Risk Assessment Program.*

M3. Evidence must include the documented personnel risk assessment programs that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R3 – Personnel Risk Assessment Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-AB-5.1 Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	Process to confirm identity.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to confirm identity.
3.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	Process to perform a seven year criminal history records check as part of each personnel risk assessment that includes: 3.2.1. current residence, regardless of duration; and 3.2.2. other locations where, during the seven years immediately prior to the date of the criminal history records check, the subject has resided for six consecutive **months** or more. If it is not possible to perform a full seven year criminal history records check, conduct as much of the seven year criminal history records check as possible and document the reason the full seven year criminal history records check could not be performed.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to perform a seven year criminal history records check.

CIP-004-AB-5.1 Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	Criteria or process to evaluate criminal history records checks for authorizing access.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process to evaluate criminal history records checks.
3.4	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	Criteria or process for verifying that personnel risk assessments performed for contractors or service vendors are conducted according to parts 3.1 through 3.3.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's criteria or process for verifying contractors or service vendors personnel risk assessments.
3.5	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and	Process to ensure that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk	An example of evidence may include, but is not limited to, documentation of the Responsible Entity's process for ensuring that individuals

CIP-004-AB-5.1 Table R3 – Personnel Risk Assessment Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
	2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	assessment completed according to parts 3.1 to 3.4 within the last seven years.	with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed within the last seven years.

R4. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access management programs that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R4 – Access Management Program.*

M4. Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R4 – Access Management Program* and additional evidence to demonstrate that the access management program was implemented as described in the Measures column of the table.

CIP-004-AB-5.1 Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and	Process to authorize based on need, as determined by the Responsible Entity, except for **CIP exceptional circumstances**: 4.1.1. electronic access; 4.1.2. unescorted physical access into a **physical security perimeter**; and 4.1.3. access to designated storage locations, whether physical or electronic, for **BES cyber system information**.	An example of evidence may include, but is not limited to, dated documentation of the process to authorize electronic access, unescorted physical access in a **physical security perimeter**, and access to designated storage locations, whether physical or electronic, for **BES cyber system information**.

CIP-004-AB-5.1 Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
	2. **physical access control systems**.		
4.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	Verify at least once each calendar quarter that individuals with active electronic access or unescorted physical access have authorization records.	Examples of evidence may include, but are not limited to: • dated documentation of the verification between the system generated list of individuals who have been authorized for access (i.e., workflow database) and a system generated list of personnel who have access (i.e., user account listing), or • dated documentation of the verification between a list of individuals who have been authorized for access (i.e., authorization forms) and a list of individuals provisioned for access (i.e., provisioning forms or shared account listing).
4.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control**	For electronic access, verify at least once every 15 **months** that all user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and are those that the Responsible Entity determines are necessary.	An example of evidence may include, but is not limited to, documentation of the review that includes all of the following: 1. a dated listing of all accounts/account groups or roles within the system; 2. a summary description of privileges associated with each group or role; 3. accounts assigned to the group or role; and 4. dated evidence showing verification of the privileges for the group are

CIP-004-AB-5.1 Table R4 – Access Management Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
	systems.		authorized and appropriate to the work function performed by people assigned to each account.
4.4	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	Verify at least once every 15 **months** that access to the designated storage locations for **BES cyber system information**, whether physical or electronic, are correct and are those that the Responsible Entity determines are necessary for performing assigned work functions.	An example of evidence may include, but is not limited to, the documentation of the review that includes all of the following: 1. a dated listing of authorizations for **BES cyber system information**; 2. any privileges associated with the authorizations; and 3. dated evidence showing a verification of the authorizations and any privileges were confirmed correct and the minimum necessary for performing assigned work functions.

R5. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access revocation programs that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R5 – Access Revocation.*

M5. Evidence must include each of the applicable documented programs that collectively include each of the applicable requirement parts in *CIP-004-AB-5.1 Table R5 – Access Revocation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-AB-5.1 Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and	A process to initiate removal of an individual's ability for unescorted physical access and **interactive remote access** upon a termination action, and complete the	An example of evidence may include, but is not limited to, documentation of all of the following: 1. dated workflow or sign-off

CIP-004-AB-5.1 Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
	2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	removals within 24 hours of the termination action (Removal of the ability for access may be different than deletion, disabling, revocation, or removal of all access rights).	form verifying access removal associated with the termination action; and 2. logs or other demonstration showing such persons no longer have access.
5.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.	For reassignments or transfers, revoke the individual's authorized electronic access to individual accounts and authorized unescorted physical access that the Responsible Entity determines are not necessary by the end of the next **day** following the date that the Responsible Entity determines that the individual no longer requires retention of that access.	An example of evidence may include, but is not limited to, documentation of all of the following: 1. dated workflow or sign-off form showing a review of logical and physical access; and 2. logs or other demonstration showing such persons no longer have access that the Responsible Entity determines is not necessary.
5.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**. Medium Impact **BES cyber systems** with **external routable connectivity** and	For termination actions, revoke the individual's access to the designated storage locations for **BES cyber system information**, whether physical or electronic (unless already revoked according to requirement R5.1), by the end of the next **day** following the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or signoff form verifying access removal to designated physical areas or cyber systems containing **BES cyber system information** associated with the terminations and dated within the next **day** of the termination action.

CIP-004-AB-5.1 Table R5 – Access Revocation			
Part	**Applicable Systems**	**Requirements**	**Measures**
	their associated: 1. **electronic access control and monitoring systems**; and 2. **physical access control systems**.		
5.4	High Impact **BES cyber systems** and their associated: • **electronic access control and monitoring systems**.	For termination actions, revoke the individual's non-shared user accounts (unless already revoked according to parts 5.1 or 5.3) within 30 **days** of the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or signoff form showing access removal for any individual **BES cyber assets** and software applications as determined necessary to completing the revocation of access and dated within thirty calendar days of the termination actions.
5.5	High Impact **BES cyber systems** and their associated: • **electronic access control and monitoring systems**.	For termination actions, change passwords for shared account(s) known to the user within 30 **days** of the termination action. For reassignments or transfers, change passwords for shared account(s) known to the user within 30 **days** following the date that the Responsible Entity determines that the individual no longer requires retention of that access. If the Responsible Entity determines and documents that extenuating operating circumstances require a longer time period, change the password(s) within 10 **days** following the end of the operating circumstances.	Examples of evidence may include, but are not limited to: • workflow or sign-off form showing password reset within 30 **days** of the termination; • workflow or sign-off form showing password reset within 30 **days** of the reassignments or transfers; or • documentation of the extenuating operating circumstance and workflow or sign-off form showing password reset within 10 **days** following the end of the operating circumstance.

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – Electronic Security Perimeter(s)
CIP-005-AB-5

A. Introduction

1. Title: Cyber Security – Electronic Security Perimeter(s)

2. Number: CIP-005-AB-5

3. Purpose: To manage electronic access to **BES cyber systems** by specifying a controlled **electronic security perimeter** in support of protecting **BES cyber systems** against compromise that could lead to misoperation or instability in the **bulk electric system**.

4. Applicability:

4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

4.1.1. [Intentionally left blank.]

4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

4.1.5. [Intentionally left blank.]

4.1.6. [Intentionally left blank.]

4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**

of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and

categorization processes.

5. [Intentionally left blank.]

6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-AB-5 Table R1 – Electronic Security Perimeter.*

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-005-AB-5 Table R1 – Electronic Security Perimeter* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-AB-5 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact **BES cyber systems** and their associated: • **protected cyber assets** Medium Impact **BES cyber systems** and their associated: • **protected cyber assets**	All applicable **cyber assets** connected to a network via a routable protocol shall reside within a defined **electronic security perimeter**.	An example of evidence may include, but is not limited to, a list of all **electronic security perimeters** with all uniquely identifiable applicable **cyber assets** connected via a routable protocol within each **electronic security perimeter**.
1.2	High Impact **BES cyber systems** with **external routable connectivity** and their associated: • **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: • **protected cyber assets**	All **external routable connectivity** must be through an identified **electronic access point**.	An example of evidence may include, but is not limited to, network diagrams showing all external routable communication paths and the identified **electronic access points**.
1.3	**Electronic access points** for High Impact **BES cyber systems** **Electronic access points** for Medium Impact **BES cyber**	Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default.	An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed

CIP-005-AB-5 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
	systems		and that each access rule has a documented reason.
1.4	High Impact **BES cyber systems** with **dial-up connectivity** and their associated: • **protected cyber assets** Medium Impact **BES cyber systems** with **dial-up connectivity** and their associated: • **protected cyber assets**	Where technically feasible, perform authentication when establishing **dial-up connectivity** with applicable **cyber assets**.	An example of evidence may include, but is not limited to, a documented process that describes how the Responsible Entity is providing authenticated access through each dial-up connection.
1.5	**Electronic access points** for High Impact **BES cyber systems** **Electronic access points** for Medium Impact **BES cyber systems** at **control centres**	Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.	An example of evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, etc.) are implemented.

R2. Each Responsible Entity allowing Interactive Remote Access to **BES cyber systems** shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-AB -5 Table R2 – Interactive Remote Access Management.*

M2. Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-AB -5 Table R2 – Interactive Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-AB-5 Table R2 – Interactive Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact **BES cyber systems** and their associated: • **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and	Utilize an **intermediate system** such that the **cyber asset** initiating **interactive remote access** does not directly access an applicable **cyber asset**.	Examples of evidence may include, but are not limited to, network diagrams or architecture documents.

CIP-005-AB-5 Table R2 – Interactive Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	their associated: • **protected cyber assets**		
2.2	High Impact **BES cyber systems** and their associated: • **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: • **protected cyber assets**	For all **interactive remote access** sessions, utilize encryption that terminates at an **intermediate system**.	An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.
2.3	High Impact **BES cyber systems** and their associated: • **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: • **protected cyber assets**	Require multi-factor authentication for all **interactive remote access** sessions.	An example of evidence may include, but is not limited to, architecture documents detailing the authentication factors used. Examples of authenticators may include, but are not limited to, • something the individual knows such as passwords or PINs. This does not include User ID; • something the individual has such as tokens, digital certificates, or smart cards; or • something the individual is such as fingerprints, iris scans, or other biometric characteristics.

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – Physical Security of BES Cyber Systems
CIP-006-AB-5

A. Introduction

1. Title: Cyber Security – Physical Security of BES Cyber Systems

2. Number: CIP-006-AB-5

3. Purpose: To manage physical access to **BES cyber systems** by specifying a physical security plan in support of protecting **BES cyber systems** against compromise that could lead to misoperation or instability in the **bulk electric system**.

4. Applicability:

   4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities." For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

      4.1.1. [Intentionally left blank.]

      4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

         4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

            4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

            4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

         4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

         4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

         4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

      4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

      4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

      4.1.5. [Intentionally left blank.]

      4.1.6. [Intentionally left blank.]

      4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**

of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and

categorization processes.

5. [Intentionally left blank.]

6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-AB-5 Table R1 – Physical Security Plan.*

M1. Evidence must include each of the documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-AB-5 Table R1 – Physical Security Plan* and additional evidence to demonstrate implementation of the plan or plans as described in the Measures column of the table.

CIP-006-AB-5 Table R1 – Physical Security Plan

Part	Applicable Systems	Requirements	Measures
1.1	Medium Impact **BES cyber systems** without **external routable connectivity** **Physical access control systems** associated with: • High Impact **BES cyber systems**, or • Medium Impact **BES cyber systems** with **external routable connectivity**	Define operational or procedural controls to restrict physical access.	An example of evidence may include, but is not limited to, documentation that operational or procedural controls exist.
1.2	Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	Utilize at least one physical access control to allow unescorted physical access into each applicable **physical security perimeter** to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes each **physical security perimeter** and how unescorted physical access is controlled by one or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.

CIP-006-AB-5 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	Where technically feasible, utilize two or more different physical access controls (this does not require two completely independent physical access control systems) to collectively allow unescorted physical access into **physical security perimeters** to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the **physical security perimeters** and how unescorted physical access is controlled by two or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.
1.4	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	Monitor for unauthorized access through a physical access point into a **physical security perimeter**.	An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized access through a physical access point into a **physical security perimeter**.
1.5	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated:	Issue an alarm or alert in response to detected unauthorized access through a physical access point into a **physical security perimeter** to the personnel identified in the **bulk electric system cyber security incident** response plan within 15 minutes of detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized access through a physical access control into a **physical security perimeter** and additional evidence that the alarm or alert was issued and communicated as

CIP-006-AB-5 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
	1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**		identified in the **bulk electric system cyber security incident** response plan, such as manual or electronic alarm or alert logs, cell phone or pager logs, or other evidence that documents that the alarm or alert was generated and communicated.
1.6	**Physical access control systems** associated with: • High Impact **BES cyber systems**, or • Medium Impact **BES cyber systems** with **external routable connectivity**	Monitor each **physical access control system** for unauthorized physical access to a **physical access control system**.	An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized physical access to a **physical access control system**.
1.7	**Physical access control systems** associated with: • High Impact **BES cyber systems**, or • Medium Impact **BES cyber systems** with **external routable connectivity**	Issue an alarm or alert in response to detected unauthorized physical access to a **physical access control system** to the personnel identified in the **bulk electric system cyber security incident** response plan within 15 minutes of the detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized physical access to **physical access control systems** and additional evidence that the alarm or alerts was issued and communicated as identified in the **bulk electric system cyber security incident** response plan, such as alarm or alert logs, cell phone or pager logs, or other evidence that the alarm or alert was generated and communicated.
1.8	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and	Log (through automated means or by personnel who control entry) entry of each individual with authorized unescorted physical access	An example of evidence may include, but is not limited to, language in the physical security plan that describes logging and recording of

CIP-006-AB-5 Table R1 – Physical Security Plan			
Part	**Applicable Systems**	**Requirements**	**Measures**
	2. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	into each **physical security perimeter**, with information to identify the individual and date and time of entry.	physical entry into each **physical security perimeter** and additional evidence to demonstrate that this logging has been implemented, such as logs of physical access into **physical security perimeters** that show the individual and the date and time of entry into **physical security perimeter**.
1.9	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	Retain physical access logs of entry of individuals with authorized unescorted physical access into each **physical security perimeter** for at least ninety **days**.	An example of evidence may include, but is not limited to, dated documentation such as logs of physical access into **physical security perimeters** that show the date and time of entry into **physical security perimeter**.

R2. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented visitor control programs that include each of the applicable requirement parts in *CIP-006-AB-5 Table R2 – Visitor Control Program.*

M2. Evidence must include one or more documented visitor control programs that collectively include each of the applicable requirement parts in *CIP-006-AB-5 Table R2 – Visitor Control Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-AB-5 Table R2 – Visitor Control Program

Part	Applicable Systems	Requirements	Measures
2.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	Require continuous escorted access of visitors (individuals who are provided access but are not authorized for unescorted physical access) within each **physical security perimeter**, except during **CIP exceptional circumstances**.	An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within **physical security perimeters** and additional evidence to demonstrate that the process was implemented, such as visitor logs.
2.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	Require manual or automated logging of visitor entry into and exit from the **physical security perimeter** that includes date and time of the initial entry and last exit, the visitor's name, and the name of an individual point of contact responsible for the visitor, except during **CIP exceptional circumstances**.	An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within **physical security perimeters** and additional evidence to demonstrate that the process was implemented, such as dated visitor logs that include the required information.
2.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and	Retain visitor logs for at least ninety **days**.	An example of evidence may include, but is not limited to, documentation showing logs have been retained for at least ninety **days**.

CIP-006-AB-5 Table R2 – Visitor Control Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
	their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**		

R3. Each Responsible Entity shall implement one or more documented **physical access control system** maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-AB-5 Table R3 – Maintenance and Testing Program.*

M3. Evidence must include each of the documented **physical access control system** maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-AB-5 Table R3 – Maintenance and Testing Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-AB-5 Table R3 – Maintenance and Testing Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	**Physical access control systems** associated with: • High Impact **BES cyber systems**, or • Medium Impact **BES cyber systems** with **external routable connectivity** Locally mounted hardware or devices at the **physical security perimeter** associated with: • High Impact **BES cyber systems**, or • Medium Impact **BES cyber systems** with **external routable connectivity**	Maintenance and testing of each **physical access control system** and locally mounted hardware or devices at the **physical security perimeter** at least once every 24 **months** to ensure they function properly.	An example of evidence may include, but is not limited to, a maintenance and testing program that provides for testing each **physical access control system** and locally mounted hardware or devices associated with each applicable **physical security perimeter** at least once every 24 **months** and additional evidence to demonstrate that this testing was done, such as dated maintenance records, or other documentation showing testing and maintenance has been performed on each applicable device or system at least once every 24 **months**.

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – System Security Management
CIP-007-AB-5

A. Introduction

1. Title: Cyber Security – System Security Management

2. Number: CIP-007-AB-5

3. Purpose: To manage system security by specifying select technical, operational, and procedural requirements in support of protecting **BES cyber systems** against compromise that could lead to misoperation or instability in the **bulk electric system**.

4. Applicability:

4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

4.1.1. [Intentionally left blank.]

4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

4.1.5. [Intentionally left blank.]

4.1.6. [Intentionally left blank.]

4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**

of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and

categorization processes.

5. [Intentionally left blank.]

6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R1 – Ports and Services.*

M1. Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R1 – Ports and Services* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-AB-5 Table R1 – Ports and Services			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Where technically feasible, enable only logical network accessible ports that have been determined to be needed by the Responsible Entity, including port ranges or services where needed to handle dynamic ports. If a device has no provision for disabling or restricting logical ports on the device then those ports that are open are deemed needed.	Examples of evidence may include, but are not limited to: • documentation of the need for all enabled ports on all applicable **cyber assets** and **electronic access points**, individually or by group. • listings of the listening ports on the **cyber assets**, individually or by group, from either the device configuration files, command output (such as netstat), or network scans of open ports; or • configuration files of host-based firewalls or other device level mechanisms that only allow needed ports and deny all others.
1.2	High Impact **BES cyber systems** Medium Impact **BES cyber systems** at **control centres**	Protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or removable	An example of evidence may include, but is not limited to, documentation showing types of protection of physical input/output ports, either

CIP-007-AB-5 Table R1 – Ports and Services			
Part	**Applicable Systems**	**Requirements**	**Measures**
		media.	logically through system configuration or physically using a port lock or signage.

R2. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R2 – Security Patch Management.*

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R2 – Security Patch Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-AB-5 Table R2 – Security Patch Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	A patch management process for tracking, evaluating, and installing cyber security patches for applicable **cyber assets**. The tracking portion shall include the identification of a source or sources that the Responsible Entity tracks for the release of cyber security patches for applicable **cyber assets** that are updateable and for which a patching source exists.	An example of evidence may include, but is not limited to, documentation of a patch management process and documentation or lists of sources that are monitored, whether on an individual **BES cyber system** or **cyber asset** basis.
2.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	At least once every 35 **days**, evaluate security patches for applicability that have been released since the last evaluation from the source or sources identified in part 2.1.	An example of evidence may include, but is not limited to, an evaluation conducted by, referenced by, or on behalf of a Responsible Entity of security-related patches released by the documented sources at least once every 35 **days**.

CIP-007-AB-5 Table R2 – Security Patch Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**		
2.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	For applicable patches identified in part 2.2, within 35 **days** of the evaluation completion, take one of the following actions: • apply the applicable patches; or • create a dated mitigation plan; or • revise an existing mitigation plan. Mitigation plans shall include the Responsible Entity's planned actions to mitigate the vulnerabilities addressed by each security patch and a timeframe to complete these mitigations.	Examples of evidence may include, but are not limited to: • records of the installation of the patch (e.g., exports from automated patch management tools that provide installation date, verification of **BES cyber system** component software revision, or registry exports that show software has been installed); or • a dated plan showing when and how the vulnerability will be addressed, to include documentation of the actions to be taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch and a timeframe for the completion of these mitigations.
2.4	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and	For each mitigation plan created or revised in part 2.3, implement the plan within the timeframe specified in the plan, unless a revision to the plan or an extension to the timeframe specified in part 2.3 is approved by the **CIP senior**	An example of evidence may include, but is not limited to, records of implementation of mitigations.

CIP-007-AB-5 Table R2 – Security Patch Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	**manager** or delegate.	

R3. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R3 – Malicious Code Prevention.*

M3. Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R3 – Malicious Code Prevention* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-AB-5 Table R3 – Malicious Code Prevention			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Deploy method(s) to deter, detect, or prevent malicious code.	An example of evidence may include, but is not limited to, records of the Responsible Entity's performance of these processes (e.g., through traditional antivirus, system hardening, policies, etc.).
3.2	High Impact **BES cyber systems** and their associated:	Mitigate the threat of detected malicious code.	Examples of evidence may include, but are not limited to:

CIP-007-AB-5 Table R3 – Malicious Code Prevention			
Part	**Applicable Systems**	**Requirements**	**Measures**
	1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**		• records of response processes for malicious code detection • records of the performance of these processes when malicious code is detected.
3.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	For those methods identified in part 3.1 that use signatures or patterns, have a process for the update of the signatures or patterns. The process must address testing and installing the signatures or patterns.	An example of evidence may include, but is not limited to, documentation showing the process used for the update of signatures or patterns.

R4. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R4 – Security Event Monitoring.*

M4. Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R4 – Security Event Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-AB-5 Table R4 – Security Event Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
4.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Log events at the **BES cyber system** level (per **BES cyber system** capability) or at the **cyber asset** level (per **cyber asset** capability) for identification of, and after-the-fact investigations of, **cyber security incidents** that includes, as a minimum, each of the following types of events: 4.1.1. detected successful login attempts; 4.1.2. detected failed access attempts and failed login attempts; 4.1.3. detected malicious code.	Examples of evidence may include, but are not limited to, a paper or system generated listing of event types for which the **BES cyber system** is capable of detecting and, for generated events, is configured to log. This listing must include the required types of events.
4.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Generate alerts for security events that the Responsible Entity determines necessitates an alert, that includes, as a minimum, each of the following types of events (per **cyber asset** or **BES cyber system** capability): 4.2.1. detected malicious code from part 4.1; and 4.2.2. detected failure of part 4.1 event logging.	Examples of evidence may include, but are not limited to, paper or system generated listing of security events that the Responsible Entity determined necessitate alerts, including paper or system generated list showing how alerts are configured.
4.3	High Impact **BES cyber systems** and their associated:	Where technically feasible, retain applicable event logs identified in part 4.1 for at least	Examples of evidence may include, but are not limited to, documentation of the event log

CIP-007-AB-5 Table R4 – Security Event Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
	1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** at **control centres** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	the last 90 consecutive **days** except under **CIP exceptional circumstances**.	retention process and paper or system generated reports showing log retention configuration set at 90 **days** or greater.
4.4	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	Review a summarization or sampling of logged events as determined by the Responsible Entity at intervals no greater than 15 **days** to identify undetected **cyber security incidents**.	Examples of evidence may include, but are not limited to, documentation describing the review, any findings from the review (if any), and dated documentation showing the review occurred.

R5. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-AB-5 Table R5 – System Access Controls.*

M5. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts *in CIP-007-AB-5 Table 5 – System Access Controls* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-AB-5 Table R5 – System Access Controls			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control**	Have a method(s) to enforce authentication of interactive user access, where technically feasible.	An example of evidence may include, but is not limited to, documentation describing how access is authenticated.

CIP-007-AB-5 Table R5 – System Access Controls			
Part	**Applicable Systems**	**Requirements**	**Measures**
	systems; and 3. **protected cyber assets** Medium Impact **BES cyber systems** at **control centres** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**		
5.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Identify and inventory all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s).	An example of evidence may include, but is not limited to, a listing of accounts by account types showing the enabled or generic account types in use for the **BES cyber system**.

CIP-007-AB-5 Table R5 – System Access Controls			
Part	**Applicable Systems**	**Requirements**	**Measures**
5.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Identify individuals who have authorized access to shared accounts.	An example of evidence may include, but is not limited to, listing of shared accounts and the individuals who have authorized access to each shared account.
5.4	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Change known default passwords, per **cyber asset** capability.	Examples of evidence may include, but are not limited to: • records of a procedure that passwords are changed when new devices are in production; or • documentation in system manuals or other vendor documents showing default vendor passwords were generated pseudo-randomly and are thereby unique to the device.
5.5	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**;	For password-only authentication for interactive user access, either technically or procedurally enforce the following password	Examples of evidence may include, but are not limited to: • system-generated reports or screen-shots of the

CIP-007-AB-5 Table R5 – System Access Controls			
Part	**Applicable Systems**	**Requirements**	**Measures**
	2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	parameters: 5.5.1. password length that is, at least, the lesser of eight characters or the maximum length supported by the **cyber asset**; and 5.5.2. minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, nonalphanumeric) or the maximum complexity supported by the **cyber asset**.	system enforced password parameters, including length and complexity; or • attestations that include a reference to the documented procedures that were followed.
5.6	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** with **external routable connectivity** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Where technically feasible, for password-only authentication for interactive user access, either technically or procedurally enforce password changes or an obligation to change the password at least once every 15 **months**.	Examples of evidence may include, but are not limited to: • system-generated reports or screen-shots of the system enforced periodicity of changing passwords; or • attestations that include a reference to the documented procedures that were followed.
5.7	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control**	Where technically feasible, either: • limit the number of unsuccessful authentication attempts; or	Examples of evidence may include, but are not limited to: • documentation of the account-lockout parameters; or

CIP-007-AB-5 Table R5 – System Access Controls			
Part	**Applicable Systems**	**Requirements**	**Measures**
	systems; and 3. **protected cyber assets** Medium Impact **BES cyber systems** at **control centres** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	• generate alerts after a threshold of unsuccessful authentication attempts.	• rules in the alerting configuration showing how the system notified individuals after a determined number of unsuccessful login attempts.

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – Incident Reporting and Response Planning
CIP-008-AB-5

A. Introduction

1. Title: Cyber Security – Incident Reporting and Response Planning

2. Number: CIP-008-AB-5

3. Purpose: To mitigate the risk to the reliable operation of the **bulk electric system** as the result of a **cyber security incident** by specifying incident response requirements.

4. Applicability:

4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

4.1.1. [Intentionally left blank.]

4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

4.1.5. [Intentionally left blank.]

4.1.6. [Intentionally left blank.]

4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power**

of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and

categorization processes.

5. [Intentionally left blank.]

6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall document one or more **cyber security incident** response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-AB-5 Table R1 – Cyber Security Incident Response Plan Specifications.*

M1. Evidence must include each of the documented plan(s) that collectively include each of the applicable requirement parts in *CIP-008-AB-5 Table R1 – Cyber Security Incident Response Plan Specifications.*

CIP-008-AB-5 Table R1 – Cyber Security Incident Response Plan Specifications

Part	Applicable Systems	Requirements	Measures
1.1	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	One or more processes to identify, classify, and respond to **cyber security incidents**.	An example of evidence may include, but is not limited to, dated documentation of **cyber security incidents** response plan(s) that include the process to identify, classify, and respond to **cyber security incidents**.
1.2	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	One or more processes to determine if an identified **cyber security incident** is a **reportable cyber security incident** and notify the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), unless prohibited by law. Initial notification to the ES-ISAC, which may be only a preliminary notice, shall not exceed one hour from the determination of a **reportable cyber security incident**.	Examples of evidence may include, but are not limited to, dated documentation of **cyber security incident** response plan(s) that provide guidance or thresholds for determining which **cyber security incidents** are also **reportable cyber security incidents** and documentation of initial notices to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC).
1.3	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	The roles and responsibilities of **cyber security incident** response groups or individuals.	An example of evidence may include, but is not limited to, dated **cyber security incident** response process(es) or procedure(s) that define roles and responsibilities (e.g.,

CIP-008-AB-5 Table R1 – Cyber Security Incident Response Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
			monitoring, reporting, initiating, documenting, etc.) of **cyber security incident** response groups or individuals.
1.4	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	Incident handling procedures for **cyber security incidents**.	An example of evidence may include, but is not limited to, dated for **cyber security incident** response process(es) or procedure(s) that address incident handling (e.g., containment, eradication, recovery/incident resolution).

R2. Each Responsible Entity shall implement each of its documented **cyber security incident** response plans to collectively include each of the applicable requirement parts in *CIP-008-AB-5 Table R2 – Cyber Security Incident Response Plan Implementation and Testing.*

M2. Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-008-AB-5 Table R2 – Cyber Security Incident Response Plan Implementation and Testing.*

CIP-008-AB-5 Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	Test each **cyber security incident** response plan(s) at least once every 15 **months**: • by responding to an actual **reportable cyber security incident**; • with a paper drill or tabletop exercise of a **reportable cyber security incident**; or • with an operational exercise of a **reportable cyber security incident**.	Examples of evidence may include, but are not limited to, dated evidence of a lessons-learned report that includes a summary of the test or a compilation of notes, logs, and communication resulting from the test. Types of exercises may include discussion or operations based exercises.
2.2	High Impact **BES cyber systems** Medium Impact **BES cyber**	Use the **cyber security incident** response plan(s) under Requirement R1 when responding to a **reportable**	Examples of evidence may include, but are not limited to, incident reports, logs, and notes that were kept during the

CIP-008-AB-5 Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	**Applicable Systems**	**Requirements**	**Measures**
	systems	**cyber security incident** or performing an exercise of a **reportable cyber security incident**. Document deviations from the plan(s) taken during the response to the incident or exercise.	incident response process, and follow-up documentation that describes deviations taken from the plan during the incident or exercise.
2.3	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	Retain records related to **reportable cyber security incident**.	An example of evidence may include, but is not limited to, dated documentation, such as security logs, police reports, emails, response forms or checklists, forensic analysis results, restoration records, and post-incident review notes related to **reportable cyber security incidents**.

R3. Each Responsible Entity shall maintain each of its **cyber security incident** response plans according to each of the applicable requirement parts in *CIP-008-AB-5 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication.*

M3. Evidence must include, but is not limited to, documentation that collectively demonstrates maintenance of each **cyber security incident** response plan according to the applicable requirement parts in *CIP-008-AB-5 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication.*

CIP-008-AB-5 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	No later than 90 **days** after completion of a **cyber security incident** response plan(s) test or actual **reportable cyber security incident** response: 3.1.1. document any lessons learned or document the absence of any lessons learned; 3.1.2. update the **cyber**	An example of evidence may include, but is not limited to, all of the following: 1. dated documentation of post incident(s) review meeting notes or follow-up report showing lessons learned associated with the **cyber security incident** response plan(s) test or actual **reportable cyber security incident**

CIP-008-AB-5 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
		security incident response plan based on any documented lessons learned associated with the plan; and 3.1.3. notify each person or group with a defined role in the **cyber security incident** response plan of the updates to the **cyber security incident** response plan based on any documented lessons learned.	response or dated documentation stating there were no lessons learned; 2. dated and revised **cyber security incident** response plan showing any changes based on the lessons learned; and 3. evidence of plan update distribution including, but not limited to: • emails; • USPS or other mail service; • electronic distribution system; or • training sign-in sheets.
3.2	High Impact **BES cyber systems** Medium Impact **BES cyber systems**	No later than 60 **days** after a change to the roles or responsibilities, **cyber security incident** response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan: 3.2.1. update the **cyber security incident** response plan(s); and 3.2.2. notify each person or group with a defined role in the **cyber security incident** response plan of the updates.	An example of evidence may include, but is not limited to: 1. dated and revised **cyber security incident** response plan with changes to the roles or responsibilities, responders or technology; and 2. evidence of plan update distribution including, but not limited to: • emails; • USPS or other mail service; • electronic distribution system; or • training sign-in sheets.

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – Recovery Plans for BES Cyber Systems
CIP-009-AB-5

A. Introduction

1. Title: Cyber Security – Recovery Plans for BES Cyber Systems

2. Number: CIP-009-AB-5

3. Purpose: To recover reliability functions performed by **BES cyber systems** by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the **bulk electric system**.

4. Applicability:

   4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

      4.1.1. [Intentionally left blank.]

      4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

         4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

            4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

            4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

         4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

         4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

         4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

      4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

      4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

      4.1.5. [Intentionally left blank.]

      4.1.6. [Intentionally left blank.]

      4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**;

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart**

resource;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes.

5. [Intentionally left blank.]

6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall have one or more documented recovery plans that collectively include each of the applicable requirement parts in *CIP-009-AB-5 Table R1 – Recovery Plan Specifications.*

M1. Evidence must include the documented recovery plan(s) that collectively include the applicable requirement parts in *CIP-009-AB-5 Table R1 – Recovery Plan Specifications.*

CIP-009-AB-5 Table R1 – Recovery Plan Specifications

Part	Applicable Systems	Requirements	Measures
1.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	Conditions for activation of the recovery plan(s).	An example of evidence may include, but is not limited to, one or more plans that include language identifying conditions for activation of the recovery plan(s).
1.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control**	Roles and responsibilities of responders.	An example of evidence may include, but is not limited to, one or more recovery plans that include language identifying the roles and responsibilities of responders.

CIP-009-AB-5 Table R1 – Recovery Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
	systems		
1.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	One or more processes for the backup and storage of information required to recover **BES cyber system** functionality.	An example of evidence may include, but is not limited to, documentation of specific processes for the backup and storage of information required to recover **BES cyber system** functionality.
1.4	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems** Medium Impact **BES cyber systems** at **control centres** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	One or more processes to verify the successful completion of the backup processes in Part 1.3 and to address any backup failures.	An example of evidence may include, but is not limited to, logs, workflow or other documentation confirming that the backup process completed successfully and backup failures, if any, were addressed.
1.5	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	One or more processes to preserve data, per **cyber asset** capability, for determining the cause of a **cyber security incident** that triggers activation of the recovery plan(s). Data preservation should not	An example of evidence may include, but is not limited to, procedures to preserve data, such as preserving a corrupted drive or making a data mirror of the system before proceeding with recovery.

CIP-009-AB-5 Table R1 – Recovery Plan Specifications			
Part	**Applicable Systems**	**Requirements**	**Measures**
	Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	impede or restrict recovery.	

R2. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, its documented recovery plan(s) to collectively include each of the applicable requirement parts in *CIP-009-AB-5 Table R2 – Recovery Plan Implementation and Testing.*

M2. Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-009-AB-5 Table R2 – Recovery Plan Implementation and Testing.*

CIP-009-AB-5 Table R2 – Recovery Plan Implementation and Testing			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems** Medium Impact **BES cyber systems** at **control centres** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	Test each of the recovery plans referenced in requirement R1 at least once every 15 **months**: • by recovering from an actual incident; • with a paper drill or tabletop exercise; or • with an operational exercise.	An example of evidence may include, but is not limited to, dated evidence of a test (by recovering from an actual incident, with a paper drill or tabletop exercise, or with an operational exercise) of the recovery plan at least once every 15 **months**. For the paper drill or full operational exercise, evidence may include meeting notices, minutes, or other records of exercise findings.
2.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and	Test a representative sample of information used to recover **BES cyber system** functionality at least once every 15 **months** to ensure that the information is useable	An example of evidence may include, but is not limited to, operational logs or test results with criteria for testing the usability (e.g. sample tape load, browsing tape contents)

CIP-009-AB-5 Table R2 – Recovery Plan Implementation and Testing			
Part	**Applicable Systems**	**Requirements**	**Measures**
	2. **physical access control systems** Medium Impact **BES cyber systems** at **control centres** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	and is compatible with current configurations. An actual recovery that incorporates the information used to recover **BES cyber system** functionality substitutes for this test.	and compatibility with current system configurations (e.g. manual or automated comparison checkpoints between backup media contents and current configuration).
2.3	High Impact **BES cyber systems**	Test each of the recovery plans referenced in requirement R1 at least once every 36 **months** through an operational exercise of the recovery plans in an environment representative of the production environment. An actual recovery response may substitute for an operational exercise.	Examples of evidence may include, but are not limited to, dated documentation of: • an operational exercise at least once every 36 **months** between exercises, that demonstrates recovery in a representative environment; or • an actual recovery response that occurred within the 36 **month** timeframe that exercised the recovery plans.

R3. Each Responsible Entity shall maintain each of its recovery plans in accordance with each of the applicable requirement parts in *CIP-009-AB-5 Table R3 – Recovery Plan Review, Update and Communication.*

M3. Acceptable evidence includes, but is not limited to, each of the applicable requirement parts in *CIP-009-AB-5 Table R3 – Recovery Plan Review, Update and Communication.*

CIP-009-AB-5 Table R3 – Recovery Plan Review, Update and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring**	No later than 90 **days** after completion of a recovery plan test or actual recovery: 3.1.1. document any lessons	An example of evidence may include, but is not limited to, all of the following: 1. dated documentation of

CIP-009-AB-5 Table R3 – Recovery Plan Review, Update and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
	systems; and 2. **physical access control systems** Medium Impact **BES cyber systems** at **control centres** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	learned associated with a recovery plan test or actual recovery or document the absence of any lessons learned; 3.1.2. update the recovery plan based on any documented lessons learned associated with the plan; and 3.1.3. notify each person or group with a defined role in the recovery plan of the updates to the recovery plan based on any documented lessons learned.	identified deficiencies or lessons learned for each recovery plan test or actual incident recovery or dated documentation stating there were no lessons learned; 2. dated and revised recovery plan showing any changes based on the lessons learned; and 3. evidence of plan update distribution including, but not limited to: • emails; • USPS or other mail service; • electronic distribution system; or • training sign-in sheets.
3.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems** Medium Impact **BES cyber systems** at **control centres** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	No later than 60 **days** after a change to the roles or responsibilities, responders, or technology that the Responsible Entity determines would impact the ability to execute the recovery plan: 3.2.1. update the recovery plan; and 3.2.2. notify each person or group with a defined role in the recovery plan of the updates.	An example of evidence may include, but is not limited to, all of the following: 1. dated and revised recovery plan with changes to the roles or responsibilities, responders, or technology; and 2. evidence of plan update distribution including, but not limited to: • emails; • USPS or other mail service; • electronic distribution system; or

CIP-009-AB-5 Table R3 – Recovery Plan Review, Update and Communication			
Part	**Applicable Systems**	**Requirements**	**Measures**
			• training sign-in sheets.

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – Configuration Change Management and Vulnerability Assessments
CIP-010-AB-1

A. Introduction

1. Title: Cyber Security – Configuration Change Management and Vulnerability Assessments

2. Number: CIP-010-AB-1

3. Purpose: To prevent and detect unauthorized changes to **BES cyber systems** by specifying configuration change management and vulnerability assessment requirements in support of protecting **BES cyber systems** from compromise that could lead to misoperation or instability in the **bulk electric system**.

4. Applicability:

4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

4.1.1. [Intentionally left blank.]

4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

4.1.5. [Intentionally left blank.]

4.1.6. [Intentionally left blank.]

4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart**

resource;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes.

5. [Intentionally left blank.]
6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R1 – Configuration Change Management*.

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R1 – Configuration Change Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-AB-1 Table R1 – Configuration Change Management

Part	Applicable Systems	Requirements	Measures
1.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	Develop a baseline configuration, individually or by group, which shall include the following items: 1.1.1. operating system(s) (including version) or firmware where no independent operating system exists; 1.1.2. any commercially available or open-source application software (including version) intentionally installed; 1.1.3. any custom software installed; 1.1.4. any logical network accessible ports; and 1.1.5. any security patches applied.	Examples of evidence may include, but are not limited to: • a spreadsheet identifying the required items of the baseline configuration for each **cyber asset**, individually or by group; or • a record in an asset management system that identifies the required items of the baseline configuration for each **cyber asset**, individually or by group.
1.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and	Authorize and document changes that deviate from the existing baseline configuration.	Examples of evidence may include, but are not limited to: • a change request record and associated electronic authorization (performed by the individual or group with the authority to authorize the change) in a

CIP-010-AB-1 Table R1 – Configuration Change Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**		change management system for each change; or • documentation that the change was performed in accordance with the requirement.
1.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 **days** of completing the change.	An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 **days** of the date of the completion of the change.
1.4	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated:	For a change that deviates from the existing baseline configuration: 1.4.1. prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change; 1.4.2. following the change, verify that required cyber security controls determined	An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.

CIP-010-AB-1 Table R1 – Configuration Change Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
	1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	in 1.4.1 are not adversely affected; and 1.4.3. document the results of the verification.	
1.5	High Impact **BES cyber systems**	Where technically feasible, for each change that deviates from the existing baseline configuration: 1.5.1. prior to implementing any change in the production environment, test the changes in a test environment or test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and 1.5.2. document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.	An example of evidence may include, but is not limited to, a list of cyber security controls tested along with successful test results and a list of differences between the production and test environments with descriptions of how any differences were accounted for, including the date of the test.

R2. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R2 – Configuration Monitoring*.

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R2 – Configuration*

Monitoring and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-AB-1 Table R2 – Configuration Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **protected cyber assets**	Monitor at least once every 35 **days** for changes to the baseline configuration (as described in requirement R1, part 1.1). Document and investigate detected unauthorized changes.	An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any unauthorized changes that were detected.

R3. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R3– Vulnerability Assessments*.

M3. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-AB-1 Table R3 – Vulnerability Assessments* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-AB-1 Table R3 – Vulnerability Assessments			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	At least once every 15 **months**, conduct a paper or active vulnerability assessment.	Examples of evidence may include, but are not limited to: • a document listing the date of the assessment (performed at least once every 15 **months**), the controls assessed for each **BES cyber system** along with the method of assessment; or • a document listing the date of the assessment and the output of any tools used to perform the assessment.

CIP-010-AB-1 Table R3 – Vulnerability Assessments			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact **BES cyber systems**	Where technically feasible, at least once every 36 **months**: 3.2.1 perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration of the **BES cyber system** in a production environment; and 3.2.2 document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 **months**), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.
3.3	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **protected cyber assets**	Prior to adding a new applicable **cyber asset** to a production environment, perform an active vulnerability assessment of the new **cyber asset**, except for **CIP exceptional circumstances** and like replacements of the same type of **cyber asset** with a baseline configuration that models an existing baseline configuration of the previous or other existing **cyber asset**.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the new **cyber asset**) and the output of any tools used to perform the assessment.
3.4	High Impact **BES cyber systems** and their associated: 1. **electronic access**	Document the results of the assessments conducted according to parts 3.1, 3.2, and 3.3 and the action plan to	An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a

CIP-010-AB-1 Table R3 – Vulnerability Assessments			
Part	**Applicable Systems**	**Requirements**	**Measures**
	control or monitoring systems; 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; 2. **physical access control systems**; and 3. **protected cyber assets**	remediate or mitigate vulnerabilities identified in the assessments including the planned date of completing the action plan and the execution status of any remediation or mitigation action items.	list of action items, documented proposed dates of completion for the action plan, and records of the status of the action items (such as minutes of a status meeting, updates in a work order system, or a spreadsheet tracking the action items).

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – Information Protection
CIP-011-AB-1

A. Introduction

1. Title: Cyber Security – Information Protection

2. Number: CIP-011-AB-1

3. Purpose: To prevent unauthorized access to **BES cyber system information** by specifying information protection requirements in support of protecting **BES cyber systems** against compromise that could lead to misoperation or instability in the **bulk electric system**.

4. Applicability:

4.1. For the purpose of the requirements contained herein, the following list of entities will be collectively referred to as "Responsible Entities". For requirements in this **reliability standard** where a specific entity or subset of entities are the applicable entity or entities, the entity or entities are specified explicitly.

4.1.1. [Intentionally left blank.]

4.1.2. a **legal owner** of an **electric distribution system** that owns one or more of the following facilities, systems, and equipment for the protection or restoration of the **bulk electric system**:

4.1.2.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.1.2.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.1.2.1.2. performs automatic load shedding under a common control system owned by the entity in subsection 4.1.2., without human operator initiation, of 300 MW or more;

4.1.2.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.1.2.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.1.2.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.1.3. the **operator** of a **generating unit** and the **operator** of an **aggregated generating facility**;

4.1.4. the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility**;

4.1.5. [Intentionally left blank.]

4.1.6. [Intentionally left blank.]

4.1.7. the **operator** of a **transmission facility**;

4.1.8. the **legal owner** of a **transmission facility**; and

4.1.9. the **ISO**.

4.2. For the purpose of the requirements contained herein, the following facilities, systems, and equipment owned by each Responsible Entity in subsection 4.1 above are those to which these requirements are applicable. For requirements in this **reliability standard** where a specific type of facilities, system, or equipment or subset of facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. One or more of the following facilities, systems and equipment that operate at, or control elements that operate at, a nominal voltage of 25 kV or less and are owned by a **legal owner** of an **electric distribution system** or a **legal owner** of a **transmission facility** for the protection or restoration of the **bulk electric system**:

4.2.1.1. each **underfrequency load shedding** or **under voltage load shed** system that:

4.2.1.1.1. is part of a load shedding program that is subject to one or more requirements in a **reliability standard**; and

4.2.1.1.2. performs automatic load shedding under a common control system owned by one or more of the entities in subsection 4.2.1, without human operator initiation, of 300 MW or more;

4.2.1.2. each **remedial action scheme** where the **remedial action scheme** is subject to one or more requirements in a **reliability standard**;

4.2.1.3. each **protection system** (excluding **underfrequency load shedding** and **under voltage load shed**) that applies to transmission where the **protection system** is subject to one or more requirements in a **reliability standard**; and

4.2.1.4. each **cranking path** and group of elements meeting the initial switching requirements from a contracted **blackstart resource** up to and including the first **point of supply** and/or **point of delivery** of the next **generating unit** or **aggregated generating facility** to be started;

4.2.2. Responsible Entities listed in subsection 4.1 other than a **legal owner** of an **electric distribution system** are responsible for:

4.2.2.1. each **transmission facility** that is part of the **bulk electric system** except each **transmission facility** that:

4.2.2.1.1. is a transformer with fewer than 2 windings at 100 kV or higher and does not connect a contracted **blackstart resource**;

4.2.2.1.2. radially connects only to load;

4.2.2.1.3. radially connects only to one or more **generating units** or **aggregated generating facilities** with a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart resource**; or

4.2.2.1.4. radially connects to load and one or more **generating units** or **aggregated generating facilities** that have a combined **maximum authorized real power** of less than or equal to 67.5 MW and does not connect a contracted **blackstart**

resource;

4.2.2.2. a **reactive power** resource that is dedicated to supplying or absorbing **reactive power** that is connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, except those **reactive power** resources operated by an end-use customer for its own use;

4.2.2.3. a **generating unit** that is:

4.2.2.3.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW unless the **generating unit** is part of an industrial complex;

4.2.2.3.2. within a power plant which:

4.2.2.3.2.1. is not part of an **aggregated generating facility**;

4.2.2.3.2.2. is directly connected to the **bulk electric system**; and

4.2.2.3.2.3. has a combined **maximum authorized real power** rating greater than 67.5 MW unless the power plant is part of an industrial complex;

4.2.2.3.3. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.3.4. a contracted **blackstart resource**;

4.2.2.4. an **aggregated generating facility** that is:

4.2.2.4.1. directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW unless the **aggregated generating facility** is part of an industrial complex;

4.2.2.4.2. within an industrial complex with **supply transmission service** greater than 67.5 MW; or

4.2.2.4.3. a contracted **blackstart resource**;

and

4.2.2.5. **control centres** and backup **control centres**.

4.2.3. The following are exempt from this **reliability standard**:

4.2.3.1. [Intentionally left blank.]

4.2.3.2. **cyber assets** associated with communication networks and data communication links between discrete **electronic security perimeters**.

4.2.3.3. [Intentionally left blank.]

4.2.3.4. for the **legal owner** of an **electric distribution system**, the systems and equipment that are not included in subsection 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes.

5. [Intentionally left blank.]
6. [Intentionally left blank.]

B. Requirements and Measures

R1. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented information protection program(s) that collectively includes each of the applicable requirement parts in *CIP-011-AB-1 Table R1 – Information Protection*.

M1. Evidence for the information protection program must include the applicable requirement parts in *CIP-011-AB-1 Table R1 – Information Protection* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-011-AB-1 Table R1 – Information Protection			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	Method(s) to identify information that meets the definition of **BES cyber system information**.	Examples of acceptable evidence include, but are not limited to: • documented method to identify **BES cyber system information** from entity's information protection program; or • indications on information (e.g., labels or classification) that identify **BES cyber system information** as designated in the entity's information protection program; or • training materials that provide personnel with sufficient knowledge to recognize **BES cyber system information**; or • repository or electronic and physical location designated for housing **BES cyber system information** in the entity's information protection program.
1.2	High Impact **BES cyber**	Procedure(s) for protecting	Examples of acceptable

CIP-011-AB-1 Table R1 – Information Protection			
Part	**Applicable Systems**	**Requirements**	**Measures**
	systems and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**	and securely handling **BES cyber system information**, including storage, transit, and use.	evidence include, but are not limited to: • procedures for protecting and securely handling, which include topics such as storage, security during transit, and use of **BES cyber system information**; or • records indicating that **BES cyber system information** is handled in a manner consistent with the entity's documented procedure(s).

R2. Each Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts in *CIP-011-AB-1 Table R2 – BES Cyber Asset Reuse and Disposal*.

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-011-AB-1 Table R2 – BES Cyber Asset Reuse and Disposal* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-011-AB-1 Table R2 – BES Cyber Asset Reuse and Disposal			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and	Prior to the release for reuse of applicable **cyber assets** that contain **BES cyber system information** (except for reuse within other systems identified in the "Applicable Systems" column), the Responsible Entity shall take action to prevent the unauthorized retrieval of **BES cyber system information** from the **cyber asset** data storage media.	Examples of acceptable evidence include, but are not limited to: • records tracking sanitization actions taken to prevent unauthorized retrieval of **BES cyber system information** such as clearing, purging, or destroying; or • records tracking actions such as encrypting, retaining in the **physical security perimeter** or

CIP-011-AB-1 Table R2 – BES Cyber Asset Reuse and Disposal			
Part	**Applicable Systems**	**Requirements**	**Measures**
	2. **physical access control systems**; and 3. **protected cyber assets**		other methods used to prevent unauthorized retrieval of **BES cyber system information**.
2.2	High Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**; and 3. **protected cyber assets** Medium Impact **BES cyber systems** and their associated: 1. **electronic access control or monitoring systems**; and 2. **physical access control systems**; and 3. **protected cyber assets**	Prior to the disposal of applicable **cyber assets** that contain **BES cyber system information**, the Responsible Entity shall take action to prevent the unauthorized retrieval of **BES cyber system information** from the **cyber asset** or destroy the data storage media.	Examples of acceptable evidence include, but are not limited to: • records that indicate that data storage media was destroyed prior to the disposal of an applicable **cyber asset**; or • records of actions taken to prevent unauthorized retrieval of **BES cyber system information** prior to the disposal of an applicable **cyber asset**.

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Cyber Security – Implementation Plan for Version 5 CIP Security Standards
CIP-PLAN-AB-1

1. Purpose

The purpose of this **reliability standard** is to set the effective dates for the Version 5 CIP Cyber Security **reliability standards** and describe compliance timelines for planned and unplanned changes that result in a higher categorization for a **BES cyber system**.

2. Applicable Reliability Standards

This **reliability standard** applies to the Version 5 CIP Cyber Security **reliability standards**, which are:

- CIP–002–AB-5.1, *Cyber Security — BES Cyber System Categorization*;
- CIP–003–AB-5, *Cyber Security — Security Management Controls*;
- CIP–004–AB-5.1, *Cyber Security — Personnel and Training*;
- CIP–005–AB-5, *Cyber Security — Electronic Security Perimeter(s)*;
- CIP–006–AB-5, *Cyber Security — Physical Security of BES Cyber Systems*;
- CIP–007–AB-5, *Cyber Security — Systems Security Management*;
- CIP–008–AB-5, *Cyber Security — Incident Reporting and Response Planning*;
- CIP–009–AB-5, *Cyber Security — Recovery Plans for BES Cyber Systems*;
- CIP–010–AB-1, *Cyber Security — Configuration Change Management and Vulnerability Assessments*; and
- CIP–011–AB-1, *Cyber Security — Information Protection*.

3. Compliance with Reliability Standards

Once the Version 5 CIP Cyber Security **reliability standards** become effective, the "Responsible Entities" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard** must comply with the requirements of those **reliability standards**.

4. Proposed Effective Date

The Version 5 Cyber Security **reliability standards**, except for requirement R2 of CIP-003-AB-5, become effective on the first **day** of the calendar quarter (January 1, April 1, July 1 or October 1) that follows eight (8) full calendar quarters after approval by the **Commission**. Requirement R2 of CIP-003-AB-5 becomes effective on the first **day** of the calendar quarter (January 1, April 1, July 1 or October 1) that follows twelve (12) full calendar quarters after approval by the **Commission**.

5. Initial Performance of Certain Periodic Requirements

Specific Version 5 CIP Cyber Security **reliability standards** have periodic requirements that contain time parameters for subsequent and recurring iterations of the requirement, such as, but not limited to, ". . . at least once every fifteen (15) **months** . . .", and "Responsible Entities" must comply initially with those periodic requirements as follows:

1. on or before the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirements:

- CIP-002-5, requirement R2; and
- CIP-003-5, requirement R1;

2. on or before the Effective Date of CIP-003-5, Requirement R2 for the following requirement:
   - CIP-003-5, requirement R2;
3. within fourteen (14) **days** after the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirement:
   - CIP-007-5, requirement R4, Part 4.4;
4. within thirty-five (35) **days** after the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirements:
   - CIP-010-1, requirement R2, Part 2.1;
5. within three (3) **months** after the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirement:
   - CIP-004-5, requirement R4, Part 4.2;
6. within twelve (12) **months** after the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirements:
   - CIP-004-5, requirement R2, Part 2.3;
   - CIP-004-5, requirement R4, Parts 4.3 and 4.4;
   - CIP-006-5, requirement R3, Part 3.1;
   - CIP-008-5, requirement R2, Part 2.1;
   - CIP-009-5, requirement R2, Parts 2.1 and 2.2; and
   - CIP-010-1, requirement R3, Part 3.1; and
7. within twenty-four (24) **months** after the effective date of the Version 5 CIP Cyber Security **reliability standards** for the following requirements:
   - CIP-009-5, requirement R2, Part 2.3; and
   - CIP-010-1, requirement R3, Part 3.2.

6. Planned or Unplanned Changes Resulting in a Higher Categorization

Planned changes refer to any changes of the electric system or **BES cyber system** as identified through the annual assessment under CIP-002-AB-5.1, requirement R2, which were planned and implemented by the “Responsible Entity” identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard**.

In contrast, unplanned changes refer to any changes of the electric system or **BES cyber system**, as identified through the annual assessment under CIP-002-AB-5.1, Requirement R2, which were not planned by the “Responsible Entity” identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard**.

For planned changes resulting in a higher categorization, the "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard** shall comply with all applicable requirements in the Version 5 CIP Cyber Security **reliability standards** on the update of the identification and categorization of the affected **BES cyber system** and any applicable and associated **physical access control systems**, **electronic access control or monitoring systems** and **protected cyber assets**, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* above.

For unplanned changes resulting in a higher categorization, the "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard** shall comply with all applicable requirements in the Version 5 CIP Cyber Security **reliability standards**, according to the following timelines, following the identification and categorization of the affected **BES cyber system** and any applicable and associated **physical access control systems**, **electronic access control or monitoring systems** and **protected cyber assets**, with additional time to comply for requirements in the same manner as those timelines specified in the section *Initial Performance of Certain Periodic Requirements* above.

Scenario of Unplanned Changes After the Effective Date for Each Version 5 CIP Cyber Security Reliability Standard	Compliance Implementation
New High Impact **BES cyber system**	twelve (12) **months**
New Medium Impact **BES cyber system**	twelve (12) **months**
Newly categorized High Impact **BES cyber system** from Medium Impact **BES cyber system**	twelve (12) **months** for requirements not applicable to Medium Impact **BES Cyber Systems**
Newly categorized Medium Impact **BES cyber system**	twelve (12) **months**
The "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard** identifies first Medium Impact or High Impact **BES cyber system** (i.e., the "Responsible Entity" identified in the applicability section of each Version 5 CIP Cyber Security **reliability standard** previously had no **BES cyber systems** categorized as High Impact or Medium Impact according to the CIP-002-AB-5.1 identification and categorization processes)	twenty-four (24) **months**

Revision History

Date	Description
2017-10-01	Initial release.

Alberta Reliability Standard
Telecommunications
COM-001-AB1-1.1

1. Purpose

The purpose of this **reliability standard** is to ensure the **ISO** and each **operator** of a **transmission facility** have adequate and reliable voice and message telecommunication facilities internally and with others for the exchange of **interconnection** and operating information necessary to maintain reliability.

2. Applicability

This **reliability standard** applies to the following:

(a) the **operator** of a **transmission facility** that is:

(i) part of the **bulk electric system**; or

(ii) not part of the **bulk electric system** but which the **ISO**:

(A) determines is necessary for the reliable operation of either the **interconnected electric system** or the City of Medicine Hat electric system; and

(B) publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1; and

(b) the **ISO**.

3. Requirements

R1 The **ISO** must, as necessary to maintain reliability, provide adequate, reliable, and, where applicable, diverse and redundant voice and message telecommunication facilities for the exchange of **interconnection** and internal Alberta operating information with the following:

(a) each **operator** of a **transmission facility**;

(b) each adjacent **interconnected transmission operator** directly connected to Alberta;

(c) each adjacent **balancing authority** directly connected to Alberta; and

(d) the adjacent **reliability coordinators**.

R2 Each **operator** of a **transmission facility** must, as necessary to maintain reliability, provide adequate, reliable, and, where applicable, diversely routed and redundant voice and message telecommunication facilities for the exchange of **interconnection** and Alberta operating information with the following:

(a) each adjacent **operator** of a **transmission facility**;

(b) each adjacent **interconnected transmission operator** that is directly connected to Alberta; and

(c) the **ISO**.

R3 The **ISO** and each **operator** of a **transmission facility** must manage and test its alternate voice and message telecommunication facilities.

R4 The **ISO** must provide a means to coordinate voice and message telecommunications with each **operator** of a **transmission facility**, adjacent **interconnected transmission operator**, adjacent

balancing authority and adjacent **reliability coordinators**, which coordination must include the ability to investigate and recommend solutions to voice and message telecommunications problems within Alberta.

R5 Each **operator** of a **transmission facility** must provide a means to coordinate voice and message telecommunications with the **ISO** and adjacent **interconnected transmission operators**, which coordination must include the ability to investigate and recommend solutions to voice and message telecommunications problems within Alberta.

R6 The **ISO** and each **operator** of a **transmission facility** must use the English language for all communications between their respective operating personnel responsible for the real-time generation control and operation of the **interconnected electric system**.

R7 The **ISO** and each **operator** of a **transmission facility** must have written operating instructions and procedures to enable continued operation of the **interconnected electric system** during the loss of voice and message telecommunications facilities.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of providing voice and message telecommunication facilities as required in requirement R1 exists. Evidence may include:

(a) a list identifying each telecommunication facility for the exchange of **interconnection** and Alberta operating information; and

(b) documentation demonstrating the implementation of diverse routing and redundancy capability.

MR2 Evidence of providing voice and message telecommunication facilities as required in requirement R2 exists. Evidence may include:

(a) a list identifying each telecommunication facility for the exchange of **interconnection** and Alberta operating information; and

(b) documentation demonstrating the implementation of diverse routing and redundancy capability, if applicable.

MR3 Evidence of managing and testing its alternate voice and message telecommunication facilities as required in requirement R3 exists. Evidence may include:

(a) a list identifying each telecommunication facility as determined to be alternate;

(b) documented procedures describing how to manage and test its alternate telecommunication facilities; and

(c) records of testing.

MR4 Evidence of providing a means to coordinate voice and message telecommunications as required in requirement R4 exists. Evidence may include a documented procedure in place which identifies a process for coordinating telecommunications and a process for investigating and recommending solutions to telecommunications problems.

MR5 Evidence of providing a means to coordinate voice and message telecommunications as required in requirement R5 exists. Evidence may include a documented procedure in place which identifies a

process for coordinating telecommunications and a process for investigating and recommending solutions to telecommunications problems.

MR6 Evidence of using the English language as required in requirement R6 exists. Evidence may include **operator** logs, voice recordings, electronic communications or **e-tag** records.

MR7 Evidence of having written operating instructions and procedures as required in requirement R7 exists. Evidence may include electronic or hard copy of the operating instructions and procedures.

5. Appendices

Appendix 1 – *Amending Process for List of Facilities*

Revision History

Effective	Description
2013-10-01	Initial Release
2015-05-01	Revised for ISO assumption of RC functionality for the Alberta footprint

Appendix 1
Amending Process for List of Facilities

In order to amend the list referenced in subsections (a)(ii)(B) of section 2, *Applicability*, the **ISO** must:

(a) upon determining that a **transmission facility** is to be added, notify the **operator** in writing and determine an effective date, which must be no less than thirty (30) **days** after the date of notice, for the **operator** to meet the applicable requirements;

(b) upon determining that a **transmission facility** is to be deleted, notify the **operator** in writing and determine an effective date for the **operator** to no longer be required to meet the applicable requirements; and

(c) publish the amended list with effective dates on the AESO website.

1. Purpose

The purpose of this **reliability standard** is to ensure the **ISO** and entities subject to this **reliability standard** have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition, and to ensure communications by operating personnel are effective.

2. Applicability

This **reliability standard** applies to:

(a) the **operator** of a **generating unit** that is:

(i) directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and

(ii) not part of an **aggregated generating facility**;

(b) the **operator** of an **aggregated generating facility** that is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(c) the **operator** of a **transmission facility**; and

(d) the **ISO**.

3. Requirements

R1 The **ISO** must have voice and data communication facilities with:

(a) each **operator** of a **transmission facility**;

(b) each adjacent **interconnected transmission operator** directly connected to Alberta; and

(c) each **adjacent balancing authority** directly connected to Alberta;

R2 The **operator** of a **transmission facility** must have voice and data communication facilities with:

(a) each adjacent **operator** of a **transmission facility**;

(b) each adjacent **interconnected transmission operator** directly connected to Alberta; and

(c) the **ISO**.

R3 Each **operator** of a **generating unit** and each **operator** of an **aggregated generating facility** must have voice and data communication facilities with:

(a) each **operator** of a **transmission facility** to which it is directly connected; and

(b) the **ISO**.

R4 The **ISO**, each **operator** of a **transmission facility**, each **operator** of an **aggregated generating facility** and each **operator** of a **generating unit** must have personnel available for all hours of the **day**, seven (7) **days** a week, to receive and respond to any voice or data communication regarding a real-time **system emergency** condition via the communication facilities as identified in requirements R1 through R3.

R5 The **ISO** must notify all potentially affected adjacent **interconnected transmission operators** and **adjacent balancing authorities** through predetermined communication paths:

(a) of any threat to the **reliability** of the **interconnected electric system**; or

(b) if the **ISO** anticipates shedding **firm load**.

R6 The **ISO** must, when issuing a verbal **directive**, do so in a clear, concise and definitive manner, identify the instruction as a **directive**, and:

(a) if the recipient of the **directive** does not respond by repeating the information in the **directive**, then the **ISO** must request the recipient to repeat the information in the **directive**;

(b) if the information in the response is not correct, the **ISO** must repeat the **directive** to resolve any misunderstandings; and

(c) if the information is repeated correctly, the **ISO** must acknowledge this to the recipient.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of having voice and data communication facilities as required in requirement R1 exists. Evidence may include a list of communication facilities or other equivalent evidence that confirms that the communications have been provided.

MR2 Evidence of having voice and data communications as required in requirement R2 exists. Evidence may include a list of communication facilities or other equivalent evidence that confirms that the communications have been provided.

MR3 Evidence of having voice and data communications as required in requirement R3 exists. Evidence may include a list of communication facilities or other equivalent evidence that confirms that the communications have been provided.

MR4 Evidence of having personnel available as required in requirement R4 exists. Evidence may include **operator** logs, timesheets, on-call lists or shift schedules.

MR5 Evidence of notifying entities as required in requirement R5 exists. Evidence may include **operator** logs or voice recordings.

MR6 Evidence of issuing verbal **directives** as required in requirement R6 exists. Evidence may include voice recordings or **operator** logs.

Revision History

Effective	Description
2013-10-01	Initial release
2014-01-01	Administrative update to standardize formatting, definitions and drafting style. Removed references to the WECC Reliability Coordinator.

Alberta Reliability Standard
Emergency Operations Planning
EOP-001-AB1-2.1b

1. Purpose

The purpose of this **reliability standard** is to define requirements for the development, maintenance, implementation and coordination of plans to mitigate operating emergencies.

2. Applicability

This **reliability standard** applies to:

(a) the **operator** of a **transmission facility** that is part of the **bulk electric system**; and
(b) the **ISO**.

This **reliability standard** does not apply to the **operator** of a **transmission facility** whose **transmission facility** is a radial connection from a **generating unit** or an **aggregated generating facility** to either the **transmission system** or to **transmission facilities** within the city of Medicine Hat.

3. Requirements

R1 The **ISO** must, as appropriate, have operating agreements with adjacent **balancing authorities** that contain provisions for **emergency assistance**.

R2 The **ISO** must develop, maintain and implement a capacity and energy emergency plan to mitigate insufficient generating capacity.

R3 Each of the **ISO** and the **operator** of a **transmission facility** must develop, maintain and implement plans to mitigate operating emergencies on the **transmission system**.

R4 Each of the **ISO** and the **operator** of a **transmission facility** must develop, maintain and implement plans for load shedding.

R5 Each of the **ISO** and the **operator** of a **transmission facility** must include, at a minimum, when developing emergency plans as identified in requirements R2, R3 and R4, the following:

(a) communication protocols to be used during operating emergencies;

(b) a list of controlling actions to resolve the operating emergency within **NERC** established timelines, including, where appropriate, a controlling action to reduce load;

(c) the tasks to be coordinated with and among any affected **operator** of a **transmission facility**, adjacent **interconnected transmission operator** and adjacent **balancing authority**, as appropriate; and

(d) a procedure for adjusting staffing levels for the emergency, where appropriate.

R6 The **ISO** must consider the elements in Appendix 1 when developing a capacity and energy emergency plan in accordance with requirement R2.

R7 The **ISO** must review its capacity and energy emergency plan, plans to mitigate operating emergencies on the **transmission system** and plans for load shedding once every calendar year and update as required.

R8 Each **operator** of a **transmission facility** must review its plans for load shedding once every calendar year and update as required.

R9 The **ISO** must provide a copy of its updated capacity and energy emergency plan, plans for load shedding and plans to mitigate operating emergencies on the **transmission system** to any affected:

(a) **operator** of a **transmission facility**;

(b) adjacent **interconnected transmission operator**; and

(c) adjacent **balancing authority**.

R10 Each **operator** of a **transmission facility** must provide a copy of its updated plans to mitigate operating emergencies on the **transmission system** and plans for load shedding to any affected adjacent **operator** of a **transmission facility** and the **ISO**.

4 Measures

The following measures correspond to the requirements identified in Section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of having at least one (1) operating agreement with an adjacent **balancing authority** as required in requirement R1 exists.

MR2 Evidence of developing, maintaining and implementing a capacity and energy emergency plan as required in requirement R2 exists. Evidence may include a dated, current capacity and energy emergency plan and communications or training to the operating personnel.

MR3 Evidence of developing, maintaining and implementing plans to mitigate operating emergencies on the **transmission system** as required in requirement R3 exists. Evidence may include dated, current plans to mitigate operating emergencies on the **transmission system** and communications or training to the operating personnel.

MR4 Evidence of developing, maintaining and implementing load shedding plans as required in requirement R4 exists. Evidence may include dated, current plans for load shedding and communications or training to the operating personnel.

MR5 Evidence of including the items in emergency plans as required in requirement R5 exists. Evidence may include emergency plans that contain items listed in requirement R5.

MR6 Evidence of considering the elements in Appendix 1 as required in requirement R6 exists. Evidence may include documentation indicating which elements from Appendix 1 were not included in the capacity and emergency plan and the rationale why they were not included.

MR7 Evidence of reviewing and updating each plan as required in requirement R7 exists. Evidence may include documentation confirming each plan was reviewed once every calendar year and updated as required.

MR8 Evidence of reviewing and updating plans as required in requirement R8 exists. Evidence may include documentation confirming each plan was reviewed once every calendar year and updated as required.

MR9 Evidence of providing each updated plan as required in requirement R9 exists. Evidence may include email or mail to appropriate recipients that identifies contents submitted.

MR10 Evidence of providing updated plans as required in requirement R10 exists. Evidence may include email or mail to appropriate recipients that identifies contents submitted.

5. Appendix 1

Elements for Consideration in Development of Capacity and Energy Emergency Plan

1. **Bulk electric system** energy use — The reduction of the **bulk electric system**'s own energy use to a minimum.
2. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.
3. Load management — Implementation of load management and voltage reductions, if appropriate.
4. Interruptible and curtailable loads — Use of interruptible and curtailable load to reduce capacity requirements or to conserve the fuel in short supply.
5. Maximizing **generating unit** output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize **generating units** and **aggregated generating facilities** during extreme cold weather.
6. Notifying independent power producers (IPP) — Notification of cogeneration and independent power producers to maximize output and availability.
7. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

8. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety and welfare of the community. Address firm load curtailment.
9. Notification of government agencies — Notification of appropriate government agencies as the various steps of the operating emergency plan are implemented.
10. Notifications to operating entities — Notifications to other operating entities as steps in the operating emergency plan are implemented.

Revision History

Effective	Description
2015-05-01	Revised for ISO assumption of RC functionality for the Alberta footprint
2014-01-01	Initial Release

EOP–002–AB1–2 Capacity and Energy Emergencies

1. Purpose

The purpose of this *reliability standard* is to ensure the ISO is prepared for a supply shortfall event.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must exercise its authority to alleviate a supply shortfall event in the *AIES*.

R2 The *ISO* must implement its capacity and energy emergency plan by following *ISO* rules.

R3 The *ISO* must communicate its current and its forecast of future system conditions to *adjacent balancing authorities* during a supply shortfall event.

R4 The *ISO* must follow plans in *ISO* rules when it anticipates a supply shortfall event may occur. The *ISO* plans must include any one of or combination of the following:

- Issuing directives as necessary, including bringing on all available generation;
- Postponing equipment maintenance;
- Posting interconnection *TTC* to maximum *reliability* based capacity and being prepared to reduce firm *load*.

R5 The *ISO* must, during a supply shortfall event:

- Only use the assistance provided by the *Interconnection's frequency bias* for the time needed to manage the event.
- Not direct generating units in an attempt to return the *Interconnection* frequency to normal beyond that supplied through *frequency bias* action and *interchange schedule* changes.

R6 The *ISO* must comply with the control performance and disturbance control standards during a supply shortfall event. If necessary to do so, the *ISO* must implement remedies including without limitation, any one of or combination of the following:

- Loading all available generating capacity.
- Deploying all available operating reserves.

- Interrupting interruptible *load* and exports.
- Requesting emergency assistance from other *balancing authorities*.
- Declaring , in accordance with *ISO* rules,an Energy Emergency Alert(s); and
- Reducing *load*, through procedures such as public appeals, voltage reductions, and curtailing interruptible *loads.*

R7 The *ISO* must comply with the control performance and disturbance control *reliability* standards during a supply shortfall event. The *ISO* must perform the following if all the remedies listed in requirement R6 have been implemented and the control performance and disturbance control standards are not being met:

R7.1 Issue directives for the manual shedding of firm *load* without delay to return its *ACE* to zero; and

R7.2 In accordance with the *ISO* rules, declare an Energy Emergency Alert.

R8 The *ISO* must notify each affected *adjacent balancing authority* in the *WECC* that a supply shortfall event exists before revising *system operating limits*.

R9 The *ISO* must complete an "Energy Emergency Alert 3 Report", using the template in Appendix 1, within two business *days* of downgrading or termination of an Energy Emergency Alert 3.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 The following must exist:

- An authorization letter signed by an officer of the *ISO* stating that the persons in the position of *system controller* have the authority to carry out actions and exercise the authority in the requirement.
- Job descriptions for *system controllers* identify the responsibilities of the *system controller* to operate to *ISO* rules and *reliability standards*.

MR2 Procedures to manage a supply shortfall event exist in *ISO rules*.

Disturbance reports, operator logs, voice recordings and/or other data exist that demonstrate the *ISO* managed a supply shortfall event in accordance with its procedures.

MR3 Evidence of communicating current and forecast system conditions as described in requirement R3 exists. Evidence may include operator logs, voice recordings, electronic communications and/or other data.

MR4 *ISO* rules must include the planning as identified in R3. Operator logs, voice recordings, electronic communications exist to show that procedures in planning for such an event were met.

MR5 Operator logs, voice recordings, electronic communications and/or other data exist to show that the requirement was met.

MR6 *ISO* rules include the remedies identified in the requirement. Operator logs, voice recordings, electronic communications and/or other data exist to show that the requirement was met.

MR7 Operator logs, voice recordings, electronic communications exist to show that requirement was met.

MR8 Evidence of notifying affected *adjacent balancing authorities* as described in requirement R8 exists. Evidence may include operator logs, voice recordings, electronic communications, electronic data or other equivalent evidence.

MR9 An "Energy Emergency Alert 3 Report" exists for each event where an Energy Emergency Alert 3 was declared.

7. Appendices

Appendix 1 - Energy Emergency Alert 3 Report (see below)

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Effective	Description
2014-01-01	Removed references to the VRC.
2009-10-03	New Issue

Appendix 1 - Energy Emergency Alert 3 Report

Requesting balancing authority:

Entity experiencing energy deficiency (if different from balancing authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other balancing authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.

2. All firm and nonfirm purchases were made regardless of cost.

3. All nonfirm sales were recalled within provisions of the sale agreement.

4. Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.

5. Available load reduction programs were exercised (public appeals, voltage reductions, etc.).

6. Operating Reserves being utilized.

Comments:

Reported By: _____

Organization: _____

Title: _____

EOP–003–AB1–1 Load Shedding Plans

1. Purpose

The purpose of this *reliability standard* is to ensure plans are in place and plans are implemented to shed *load* when there is insufficient generation or transmission capacity, to mitigate the risk of an uncontrolled failure of the *Interconnection*.

2. Applicability

This *reliability standard* applies to the entities listed below:

(a) the *operator* of a *transmission facility* that is part of the *bulk electric system*;

(b) a *market participant* receiving service under Rate DTS of the *ISO tariff*, unless such service is used solely for supplying station service to a *generating unit* or an *aggregated generating facility*;

(c) the *operator* of an *electric distribution system* who is a counterparty to an agreement with a *market participant* receiving service under Rate DTS of the *ISO tariff*, for the provision of *load* shedding services; and

(d) the *ISO.*

This *reliability standard* does not apply to the *operator* of a *transmission facility* whose *transmission facility* is a radial connection from a *generating unit* or an *aggregated generating facility* to either the *transmission system* or to *transmission facilities* within the city of Medicine Hat.

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the *Consolidated Authoritative Document Glossary*.

4. Requirements

R1 When the AIES is operating with insufficient generation or transmission capacity and after considering all remedial steps, the *ISO* must issue *directives* to shed *load*.

R1.1 Each *market participant* and *operator* of an *electric distribution system* must shed *load* or reduce *MW* inflow as directed by the *ISO*.

R1.2 When coordination with the *ISO* is not possible or practicable, and after considering all remedial steps, the *operator* of a *transmission facility*, when operating with insufficient generation or transmission capacity, must shed *load* rather than risk an uncontrolled failure of components or *cascading* of the *Interconnection*.

R2 The *ISO* must establish plans for automatic *load* shedding for *underfrequency* or under voltage conditions.

R3 The *ISO* must submit *UFLS* plans to *WECC* for coordination of *UFLS* plans among other *interconnected transmission operators* and *balancing authorities*.

R4 The *ISO* must coordinate *UVLS* plans among other *interconnected transmission operators* and *balancing authorities* external to Alberta.

R5 The *ISO* must consider one or more of these factors in designing an automatic *load* shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.

R6 The *ISO* must implement automatic *load* shedding in *MW* blocks established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R7 After the *AIES* separates from the *Interconnection*, if there is insufficient generating capacity to restore frequency following automatic *underfrequency load shedding*, the *ISO* must issue *directives* to shed additional *load*.

R8 The *ISO* must coordinate automatic *load* shedding throughout Alberta with *underfrequency* isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

R9 The *ISO* must have procedures for directing operator controlled manual *load* shedding to respond to real-time emergencies.

R10 The *ISO* must be capable of directing manual *load* shedding in a time frame adequate for responding to the emergency.

R11 Each *market participant* and *operator* of an *electric distribution system* must be capable of implementing manual *load* shedding in a time frame adequate for responding to the emergency.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

These measures will be used by the *ISO* in carrying out its *compliance monitor*ing duties in accordance with *ISO rule* 12. The *ISO* may consider other data and information, including any provided by a *market participant*.

MR1 Voice recordings and logs exist to confirm the *ISO* issued *directives* to shed *load*.

- **MR1.1** Electronic logs, metering or electronic data exists to confirm the *market participant* or *operator* of an *electric distribution system* shed *load*.
- **MR1.2** Electronic logs and/or electronic data exist to confirm the *operator of a transmission facility* shed *load*.

MR2 Automatic *load* shedding plans exist. Plans meet the defined need of *load* shedding situations.

MR3 Written confirmation from *WECC* that the *ISO* submitted *UFLS* plans.

MR4 Written confirmation from *interconnected transmission operators* and *balancing authorities* external to Alberta indicating that the *ISO* coordinated *UVLS* plans.

MR5 One or more of these factors were considered in the design of the *load* shed scheme.

MR6 One or more *MW* blocks exist in *load* shed plans or schemes.

MR7 Voice recordings and logs exist to confirm the *ISO* issued *directives* to shed additional *load*.

MR8 *ISO rules*, *interconnection* standards or studies exist to show coordination with automatic actions.

MR9 Procedures exist for directing operator controlled manual *load* shedding.

MR10 Electronic logs, and/or voice recordings exist to confirm the *ISO* directed manual *load* shedding. Manual *load* shedding is performed in a time frame adequate to respond to the emergency as defined in operating procedures or equipment ratings.

MR11 Electronic logs, metering or electronic data exists to confirm the manual *load* shedding. Manual *load* shedding is performed in a time frame adequate to respond to the emergency as defined in operating procedures or equipment ratings.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Effective	Description
2012-12-17	Administrative update – "*TFO*", "*demand customer*" and "*WSP*" replaced with "*operator of a transmission facility*", "*market participant* receiving service under Rate DTS of the *ISO tariff*" and "*operator* of an *electric distribution system*"; and other cleanup items.
2009-06-17	New Issue

Alberta Reliability Standard
Event Reporting
EOP-004-AB-2

1. Purpose

The purpose of this **reliability standard** is to improve the reliability of the **bulk electric system** by requiring the reporting of events by the **ISO**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must have an event reporting operating plan to report the events identified in Appendix 1 to the **NERC** and other organizations, as appropriate.

R2 The **ISO** must, upon recognition of a reportable event identified in Appendix 1, report the event in accordance with its event reporting operating plan as soon as practicable, but no more than five (5) **business days** following such recognition.

R3 The **ISO** must validate all contact information contained in its event reporting operating plan each calendar year.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence of having an event reporting operating plan as required in requirement R1 exists. Evidence may include, but is not limited to, an event reporting operating plan for the events identified in Appendix 1.

MR2 Evidence of reporting events as required in requirement R2 exists. Evidence may include, but is not limited to, a copy of the completed report, operator logs, voice recordings, electronic communications, or other equivalent evidence.

MR3 Evidence of validating all contact information contained in the event reporting operating plan as required in requirement R3 exists. Evidence may include, but is not limited to, dated records showing contact information, electronic communications or other equivalent evidence.

5. Appendices

Appendix 1 – *Reportable Events*

Revision History

Date	Description
2016-08-30	Initial release.

Appendix 1

Reportable Events

The following are the reportable events to be contained in the **ISO**'s event reporting operating plan, as described in requirement R1:

1. a physical threat to a **control centre** of the **ISO**, excluding a weather or natural disaster related threat, which has the potential to degrade the normal operation of a **control centre** of the **ISO**;
2. a suspicious device or activity at a **control centre** of the **ISO**;
3. a situation on the **bulk electric system** requiring a public appeal for load reduction;
4. a situation on the **bulk electric system** requiring a system-wide voltage reduction greater than or equal to 3%;
5. a situation on the **bulk electric system** requiring manual firm load shedding greater than or equal to 100 MW;
6. exceeding an **interconnection reliability operating limit** within the **interconnected electric system** for an amount of time that is greater than **interconnection reliability operating limit Tv**, or exceeding a **system operating limit** for a major transmission path identified in the table "Major WECC Transfer Paths in the Bulk Electric System", as provided by the **WECC**, for more than thirty (30) minutes;
7. a loss of firm load greater than or equal to 300 MW for fifteen (15) minutes or more;
8. an unintended **transmission system** separation within the **interconnected electric system** that results in an island of greater than or equal to 100 MW, excluding an island created by the loss of:
    a) a **transmission system** radial connection;
    b) non-**transmission system** facilities (distribution level); or
    c) the **interconnection**;
9. total generation loss, within one (1) minute, of greater than or equal to 2000 MW;
10. an unplanned evacuation of the **control centre** of the **ISO** for thirty (30) continuous minutes or more;
11. a complete loss, for thirty (30) continuous minutes or more, of voice communication systems for the **control centre** of the **ISO**; or
12. a complete loss of monitoring capability affecting the **control centre** of the **ISO** for thirty (30) continuous minutes or more that renders analysis capability, such as state estimator or contingency analysis, inoperable.

Alberta Reliability Standard
System Restoration from Blackstart Resources
EOP-005-AB-2

1. Purpose

The purpose of this **reliability standard** is to ensure plans, facilities, and personnel are prepared to enable restoration of the **interconnected electric system** starting from **blackstart resources**, to ensure **reliability** is maintained during restoration, and priority is placed on restoring the **interconnected electric system** and the **interconnection** in accordance with the **ISO**'s restoration plan.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**;

(b) the **operator** of a **transmission facility** that the **ISO** includes in its restoration plan and in a list published on the AESO website that the **ISO** may amend from time to time in accordance with the process set out in Appendix 1;

(c) the **operator** of a **generating unit** that:

(i) is not part of an **aggregated generating facility**;

(ii) has a **maximum authorized real power** rating greater than 18 MW; and

(iii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and

(d) the **operator** of an **electric distribution system** that is identified in the restoration plan of an **operator** of a **transmission facility**.

3. Requirements

R1 Each **operator** of a **transmission facility** must have a restoration plan approved by the **ISO** that allows for the restoration of the **transmission facilities** that it operates to a state whereby the choice of the next load to be restored is not driven by the need to control frequency or voltage, regardless of where the **blackstart resource** is located, following a **disturbance** in which:

(a) one or more areas of the **interconnected electric system** shuts down; and

(b) the use of **blackstart resources** is required to restore the shut-down area(s) to service.

The restoration plan must include:

R1.1 Strategies for system restoration that are coordinated with the **ISO**'s restoration plan.

R1.2 Intentionally left blank.

R1.3 Procedures for restoring:

(a) connections with other **operators** of **transmission facilities**; and

(b) **interconnections** with any adjacent **interconnected transmission operators** under the direction of the **ISO**.

R1.4 The characteristics of each **blackstart resource** that is connected to the **transmission facilities** of the **operator** of a **transmission facility**, including but not limited to the:

(a) name;

(b) location;

(c) megawatt and megavar capacity; and

(d) type of **generating unit**.

R1.5 The identification of the initial switching requirements for any facilities, operated by the **operator** of a **transmission facility**, that are a part of the **cranking paths** identified in the **ISO**'s restoration plan.

R1.6 Acceptable operating voltage and frequency limits during restoration.

R1.7 Operating processes to reestablish connections between the **transmission facilities** of the **operator** of a **transmission facility** for areas that have been restored and are prepared for reconnection.

R1.8 Operating processes to restore loads required to restore the **interconnected electric system**, such as:

(a) station service for substations;

(b) **generating units** to be restarted or stabilized; and

(c) load needed to stabilize generation and frequency, and to provide voltage control.

R1.9 Operating processes for accepting authority from and transferring authority back to the **ISO** in accordance with the **ISO**'s restoration plan.

R2 In the event of changes to the roles and specific tasks of entities identified in a restoration plan:

(a) the **ISO** must provide the affected entities identified in its restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan; and

(b) each **operator** of a **transmission facility** must provide the affected entities identified in its approved restoration plan with a description of their roles and any changes to their roles and specific tasks prior to the effective date of the plan.

R3 Each **operator** of a **transmission facility** must within sixty (60) **days**, or another time period agreed to by the **ISO,** after receiving an updated copy of the **ISO**'s restoration plan:

(a) review its restoration plan;

(b) align its restoration plan, as necessary, with the **ISO**'s restoration plan; and

(c) submit its plan to the **ISO** for approval.

R3.1 The **operator** of a **transmission facility** must, where the **ISO** disapproves a restoration plan submitted pursuant to requirement R3(c), resolve the issues described in the reasons provided by the **ISO** within a timeframe agreed to by the **ISO**.

R4 Each **operator** of a **transmission facility** must update and submit its revised restoration plan to the **ISO** for approval:

(a) within ninety (90) **days** after identifying an unplanned permanent **interconnected electric system** modification; and

(b) no less than ninety (90) **days** prior to implementing a planned **interconnected electric system** modification

that would change the implementation of its restoration plan.

R4.1 The **operator** of a **transmission facility** must, where the **ISO** disapproves a revised restoration plan submitted pursuant to requirement R4, resolve the issues described in the reasons provided by the **ISO** within a timeframe agreed to by the **ISO**.

R5 Each **operator** of a **transmission facility** must have a copy of its current **ISO** approved restoration plan within its primary and backup control rooms for the purpose of ensuring it is available to its **real time** operating personnel.

R5.1 Each **operator** of a **transmission facility** must provide a copy of its current **ISO** approved restoration plan to each **operator** of an **electric distribution system** identified in that plan.

R6 The **ISO** must verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This must be completed every five (5) years at a minimum. Such analysis, simulations or testing must verify:

R6.1 the capability of **blackstart resources** to meet the **real power** and **reactive power** requirements of the **cranking paths** and the dynamic capability to supply initial loads;

R6.2 the location and magnitude of loads required to control voltages and frequency within acceptable operating limits; and

R6.3 the capability of **generating units** required to control voltages and frequency within acceptable operating limits.

R7 Each affected **operator** of a **transmission facility** must, following a **disturbance** in which one or more areas of the **interconnected electric system** shuts down and the use of **blackstart resources** is required to restore the shut-down area to service, implement its restoration plan. If the restoration plan cannot be executed as expected, the **operator** of a **transmission facility** must use the strategies for system restoration referred to in requirement R1.1 to facilitate restoration.

R8 Each affected **operator** of a **transmission facility** must, following a **disturbance** in which one or more areas of the **interconnected electric system** shuts down and the use of **blackstart resources** is required to restore the shut-down area to service, resynchronize these areas with each applicable:

(a) neighbouring **operator** of a **transmission facility**'s area; and

(b) **interconnected transmission operator**'s area,

but only with the prior authorization of the **ISO** and in accordance with the procedures included in the **ISO**'s restoration plan.

R9 The **ISO** must have **blackstart resource** testing requirements to verify that each **blackstart resource** is capable of meeting the requirements of the **ISO**'s restoration plan. These **blackstart resource** testing requirements must include:

R9.1 The frequency of testing such that each **blackstart resource** is tested at least once every three (3) calendar years.

R9.2 A list of required tests including:

(a) a test to verify the ability of the **blackstart resource** to:

(i) start the **generating unit(s)** associated with the **blackstart resource** when isolated with no support from the **interconnected electric system**; or

(ii) remain energized without connection to the remainder of the **interconnected electric system**, if designed to do so; and

(b) upon completion of (a), a test to verify the ability of the **generating unit(s)** associated with the **blackstart resource** to energize a bus. If it is not possible to energize a bus during the test, the testing entity must otherwise demonstrate that the **generating unit(s)** associated with the **blackstart resource** has the capability to energize a bus.

R9.3 The minimum duration of each of the required tests.

R10 Each **operator** of a **transmission facility** must include system restoration training for its operating personnel once each calendar year in its operations training program. This training program must include training on the following:

(a) the **operator** of a **transmission facility**'s restoration plan including coordination with the **ISO** and each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** included in its restoration plan;

(b) restoration priorities;

(c) the building of **cranking paths** as included in its restoration plan; and

(d) synchronizing re-energized sections of the **interconnected electric system**.

R11 Each **operator** of a **transmission facility** and **operator** of an **electric distribution system** must provide a minimum of two (2) hours of system restoration training every two (2) calendar years to its field switching personnel identified as performing unique tasks associated with the **operator** of a **transmission facility**'s restoration plan that are outside of their normal tasks.

R12 Each **operator** of a **transmission facility** must participate in the **ISO**'s restoration drills, exercises, or simulations if requested by the **ISO**.

R13 The **ISO** must have written **blackstart resource** agreements or mutually agreed upon procedures or protocols with each **operator** of a **generating unit** with a **blackstart resource**, specifying the terms and conditions of their arrangement. Such agreements must include references to the **blackstart resource** testing requirements, including those specified in requirement R9.

R14 Each **operator** of a **generating unit** with a **blackstart resource** must have documented procedures for starting each **blackstart resource** and energizing a bus.

R15 Each **operator** of a **generating unit** with a **blackstart resource** must notify the **ISO** of any known changes to the capabilities of that **blackstart resource** affecting the ability of the **operator** of a **generating unit** to fulfill the requirements of the **ISO**'s restoration plan within twenty-four (24) hours of becoming aware of such change.

R16 Each **operator** of a **generating unit** with a **blackstart resource** must perform **blackstart resource** tests, and maintain records of such testing, in accordance with the testing requirements set by the **ISO** as referenced in the **blackstart resource** agreements or mutually agreed upon procedures or protocols.

R16.1 Testing records must include at a minimum:

(a) name of the **blackstart resource**;

(b) **generating unit** tested;

(c) date of the test;

(d) duration of the test;

(e) time required to start the **generating unit**; and

(f) an indication of any testing requirements not met under requirement R9.

R16.2 Each **operator** of a **generating unit** with a **blackstart resource** must provide the **blackstart resource** test results within thirty (30) **days** after receiving a request from the **ISO**.

R17 Each operator of a **generating unit** with a **blackstart resource** must provide a minimum of two (2) hours of training every two (2) calendar years to each of its operating personnel responsible for:

(a) the startup of its **blackstart resource**; and

(b) energizing a bus.

R17.1 The training program must include training on the following:

(a) those elements of the **ISO**'s restoration plan that are applicable to the **blackstart resource**, including coordination with the **ISO** and the adjacent **operator** of a **transmission facility**; and

(b) the procedures documented in requirement R14.

R18 Each **operator** of a **generating unit** must participate in the **ISO**'s restoration drills, exercises, or simulations if requested by the **ISO**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence of having a restoration plan that is approved by the **ISO** and includes the elements as required in requirement R1 exists. Evidence may include, but is not limited to:

(a) email, mail or other equivalent evidence demonstrating approval of the restoration plan by the **ISO**; and

(b) a documented restoration plan including the elements identified in requirement R1.

MR2 Evidence of providing a description of any changes to the roles and specific tasks of affected entities identified in the restoration plan as required in requirement R2 exists. Evidence may include, but is not limited to, a documented restoration plan showing the effective date and dated emails with receipts or registered mail with receipts, including a description of any changes to roles and specific tasks, or other equivalent evidence.

MR3 Evidence of reviewing, aligning and submitting the restoration plan as required in requirement R3 exists. Evidence may include, but is not limited to, a documented restoration plan, including a review or revision history, and emails with receipts or registered mail with receipts, or other equivalent evidence.

MR3.1 Evidence of resolving the issues described in the reasons provided by the **ISO** within a timeframe agreed to by the **ISO** as required in requirement R3.1 exists. Evidence may include, but is not limited to, emails with receipts or registered mail with receipts, or other equivalent evidence.

MR4 Evidence of updating and submitting the revised restoration plan as required in requirement R4 exists. Evidence may include, but is not limited to:

(a) for the date of identifying any unplanned permanent modifications: logs, a dated report, emails, or other equivalent evidence;

(b) for the date of implementing planned modifications: logs, a dated report, emails, or other equivalent evidence;

(c) for updating the restoration plan: a dated documented restoration plan and revision histories, or other equivalent evidence; and

(d) for submitting the revised restoration plan: emails with receipts or registered mail receipts including submission date, or other equivalent evidence.

MR4.1 Evidence of resolving the issues described in the reasons provided by the **ISO** within a timeframe agreed to by the **ISO** as required in requirement R4.1 exists. Evidence may include, but is not limited to, emails with receipts or registered mail with receipts, or other equivalent evidence.

MR5 Evidence of having a copy of the current **ISO** approved restoration plan within the primary and backup control rooms as required in requirement R5 exists. Evidence may include but is not limited to dated records to show that the latest **ISO** approved copy of the restoration plan is available in the primary and backup control rooms and to the **real time** operating personnel in accordance with requirement R5, or other equivalent evidence.

MR5.1 Evidence of providing a copy of the current **ISO** approved restoration plan to each **operator** of an **electric distribution system** as required in requirement R5.1 exists. Evidence may include dated emails with receipts or registered mail receipts, or other equivalent evidence.

MR6 Evidence of verifying every five (5) years that the restoration plan accomplishes its intended function as required in requirement R6 exists. Evidence may include, but is not limited to, dated event analysis assessments, dated study results, or other equivalent evidence.

MR7 Evidence of executing the restoration plan or using the restoration strategies as required in requirement R7 exists. Evidence may include, but is not limited to, sequence of events records, data files, **operator** logs, voice recordings, electronic communications, or other equivalent evidence.

MR8 Evidence of resynchronizing shut down area(s) with the **ISO**'s prior authorization and in accordance with the procedures included in the **ISO**'s restoration plan as required in requirement R8 exists. Evidence may include, but is not limited to, a dated copy of the **ISO**'s restoration plan and a combination of the following evidence as appropriate:

(a) sequence of events records;

(b) data files;

(c) **operator** logs;

(d) voice recordings;

(e) electronic communications,

or other equivalent evidence.

MR9 Evidence of having **blackstart resource** testing requirements as required in requirement R9 exists. Evidence may include, but is not limited to, **blackstart resource** testing requirement documentation, or other equivalent evidence.

MR10 Evidence of including system restoration training within the operations training program as required in requirement R10 exists. Evidence may include, but is not limited to, a documented operations training program including system restoration training for operating personnel, or other equivalent evidence.

MR11 Evidence of providing a minimum of two (2) hours of system restoration training every two (2) calendar years as required in requirement R11 exists. Evidence may include, but is not limited to, training records, training documentation including dates and duration, or other equivalent evidence.

MR12 Evidence of participating in the **ISO**'s restoration drills, exercises, or simulations as required in requirement R12 exists. Evidence may include, but is not limited to:

(1) documentation of the **ISO**'s request; and

(2) training records, participation records, training documentation, or other equivalent evidence.

MR13 Evidence of having written **blackstart resource** agreements or mutually agreed upon procedures or protocols as required in requirement R13 exists. Evidence may include, but is not limited to, executed agreements, procedures or protocols, or other equivalent evidence.

MR14 Evidence of having documented procedures for starting each **blackstart resource** and energizing a bus as required in requirement R14 exists. Evidence may include, but is not limited to, documented procedures, or other equivalent evidence.

MR15 Evidence of notifying the **ISO** of any known changes to the capabilities of the **blackstart resource** as required in requirement R15 exists. Evidence may include, but is not limited to, emails with receipts, registered mail receipts, time stamped voice record(ing)s or operator logs, showing when the **operator** of a **generating unit** with a **blackstart resource** became aware of changes to the **blackstart resource** capabilities and that it notified the **ISO** within twenty-four (24) hours of becoming aware of such changes as required in requirement R15, or other equivalent evidence.

MR16 Evidence of performing **blackstart resource** tests, maintaining records of such testing, and providing the **blackstart resource** test results as required in requirement R16 exists. Evidence may include, but is not limited to, test records, test results, and emails with receipts or registered mail receipts that show that it provided these records to the **ISO** when requested, or other equivalent evidence.

MR17 Evidence of providing a minimum of two (2) hours of training every two (2) calendar years as required in requirement R17 exists. Evidence may include, but is not limited to, training records, training dates, durations and training materials provided, or other equivalent evidence.

MR18 Evidence of participating in the **ISO**'s restoration drills, exercises, or simulations as required in requirement R18 exists. Evidence may include, but is not limited to:

(1) documentation of the **ISO**'s request; and

(2) training records, participation records, training documentation, or other equivalent evidence.

5. Appendices

Appendix 1 – *Amending Process for List of Operators of Transmission Facilities Included in the AESO Restoration Plan*

Revision History

Date	Description
2018-07-01	Initial release.

Appendix 1

Amending Process for List of Operators of Transmission Facilities included in the AESO Restoration Plan

In order to amend the list referenced in subsection (b) of section 2, *Applicability*, the **ISO** must:

(a) upon determining that an **operator** of a **transmission facility** is to be added to the list, notify each affected **operator** of a **transmission facility** in writing and determine the date on which the amended list comes into effect, which must be no less than the first day of the month following three (3) full calendar quarters (January 1, April 1, July 1, October 1) after the date of notice, for the **operator** to meet the applicable requirements;

(b) upon determining that an **operator** of a **transmission facility** is to be deleted, notify each affected **operator** of a **transmission facility** in writing and determine the date on which the amended list comes into effect such that the **operator** will no longer be required to meet the applicable requirements; and

(c) post the amended list with effective dates on the AESO website.

Alberta Reliability Standard
System Restoration Coordination
EOP-006-AB-2

1. Purpose

Ensure plans are established and personnel are prepared to enable effective coordination of the system restoration process to ensure **reliability** is maintained during restoration of the **interconnected electric system** in the event of a complete or partial **blackout**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R.1. The **ISO** must have a restoration plan for its area. The scope of the **ISO**'s restoration plan starts when contracted **blackstart resources** are utilized to re-energize a shut down area of the **bulk electric system**. The scope of the **ISO**'s restoration plan ends when each **operator** of a **transmission facility** is interconnected and the **ISO**'s area is connected to all of its neighbouring **reliability coordinator areas**, provided facilities are available to be returned to service. The restoration plan shall include:

R1.1. a strategy to be employed during restoration events for restoring the **interconnected electric system** including minimum criteria for meeting the objectives of the **ISO**'s restoration plan;

R1.2. operating processes for restoring the **interconnected electric system**;

R1.3. the elements of coordination between the **ISO** and each **operator** of a **transmission facility** in accordance with the **ISO**'s system restoration plan;

R1.4. descriptions of the elements of coordination of restoration plans with neighbouring **reliability coordinators**;

R1.5. criteria and conditions for reestablishing connections between each **operator** of a **transmission facility** within its area, with **transmission operators** in other **reliability coordinator areas**, and with other **reliability coordinators**;

R1.6. reporting requirements for the entities within the **ISO**'s area during a restoration event;

R1.7. criteria for sharing information regarding restoration with neighbouring **reliability coordinators** and with **operators** of **transmission facilities** within the **ISO**'s area; and

R1.8. identification of the **ISO** as the primary contact for disseminating information regarding restoration to neighbouring **reliability coordinators**, and to **operators** of **transmission facilities** within its area.

R1.9. Intentionally left blank.

R2. The **ISO** must distribute its most recent restoration plan to each **operator** of a **transmission facility**, as referenced in the **ISO**'s restoration plan, and to neighbouring **reliability coordinators** within thirty (30) **days** of creation or revision.

R3. The **ISO** must review its restoration plan within thirteen (13) **months** of the last review.

R4. The **ISO** must review its neighbouring **reliability coordinator**'s restoration plans.

R4.1. If the **ISO** finds conflicts between its restoration plans and any of its neighbours, the conflicts must be resolved in thirty (30) **days**.

R5. The **ISO** must review the restoration plans or procedures of **operators** of **transmission facilities** within its area that are required to be submitted to the **ISO** under any **ISO rules** or **reliability standards**.

R5.1. The **ISO** must determine whether each of the restoration plans or procedures referenced in requirement R5 is coordinated and compatible with the **ISO**'s restoration plan and each of the other restoration plans or procedures referenced in requirement R5. The **ISO** must approve or disapprove, with stated reasons, the restoration plan or procedure submitted by an **operator** of a **transmission facility** within thirty (30) **days** following the receipt of the restoration plan or procedure.

R6. The **ISO** must have, within its primary and backup control rooms, so that it is available to all of its operating personnel, a copy of its latest restoration plan and copies of the latest restoration plans or procedures of each **operator** of a **transmission facility** in the **ISO**'s area that is required to have an approved plan or procedure in accordance with any **ISO rule** or **reliability standard.**

R7. The **ISO** must work with each affected **operator** of a **generating unit**, **operator** of an **aggregated generating facility**, and **operator** of a **transmission facility** as well as neighbouring **reliability coordinators** to monitor restoration progress, coordinate restoration, and take actions to restore the **bulk electric system** frequency within acceptable operating limits. If the restoration plan cannot be completed as expected, the **ISO** must utilize its restoration plan strategies to facilitate restoration of the **interconnected electric system**.

R8. The **ISO** must coordinate or authorize resynchronizing islanded areas that bridge boundaries between each **operator** of a **transmission facility** or a boundary between the **ISO**'s area and a **reliability coordinator area**. If the resynchronization cannot be completed as expected the **ISO** must utilize its restoration plan strategies to facilitate resynchronization.

R9. The **ISO** must include within its operations training program, annual **interconnected electric system** restoration training for its operating personnel to assure the proper execution of its restoration plan. This training program must address the following

R9.1. the coordination role of the **ISO**; and

R9.2. reestablishing **WECC** Paths 1 and 83**.**

R10. The **ISO** must conduct two (2) scheduled instances of a system restoration drill, exercise, or simulation per calendar year, which must provide an opportunity for each **operator** of a **transmission facility**, **operator** of a **generating unit** and **operator** of an **aggregated generating**

facility to attend as dictated by the particular scope of the drill, exercise, or simulation that is being conducted.

R10.1. The **ISO** must request each **operator** of a **transmission facility**, **operator** of a **generating unit** and **operator** of an **aggregated generating facility**, as identified in the **ISO**'s restoration plan, to participate in a drill, exercise, or simulation at least once every two calendar years

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence of having a restoration plan as required in requirement R1 exists. Evidence may include, but is not limited to, a dated copy of the restoration plan.

MR2 Evidence of distributing the restoration plan as required in requirement R2 exists. Evidence may include, but is not limited to, e-mails with receipts or other equivalent evidence.

MR3. Evidence of reviewing the restoration plan as required in requirement R3 exists. Evidence may include, but is not limited to, a review signature sheet, or revision histories, or other equivalent evidence.

MR4. Evidence of reviewing neighboring **reliability coordinator**'s restoration plans and resolving any conflicts within thirty (30) **days** as required in requirement R4 exists.

MR5. Evidence of reviewing, approving or disapproving, and notifying each **operator** of a **transmission facility** as required in requirement R5 exists. Evidence may include, but is not limited to, a review signature sheet or emails, or other equivalent evidence.

MR6. Evidence of having copies of restoration plans as required in requirement R6 exists. Evidence may include, but is not limited to, e-mails, restoration plans or procedures documentation, or other equivalent evidence.

MR7. Evidence of monitoring and coordinating restoration progress as required in requirement R7 exists. Evidence may include, but is not limited to, voice recordings, e-mail, dated computer printouts, **operator** logs or other equivalent evidence.

MR8. If there has been a resynchronizing of an islanded area, the **ISO** and each **reliability coordinator** involved may have evidence that it coordinated or authorized resynchronizing in accordance with requirement R8. Evidence may include, but is not limited to, voice recordings, e-mails, **operator** logs or other equivalent evidence.

MR9. The **ISO** may have an electronic or hard copy of its training records available showing that it has provided training in accordance with requirement R9.

MR10. The **ISO** may have evidence that it conducted two scheduled instances of a system restoration drill, exercise, or simulation per calendar year and that **operators** of a **transmission facility** and **operators** of a **generating unit** and **operators** of an **aggregated generating facility** as identified in the **ISO**'s restoration plan were invited in accordance with requirement R10. Evidence may include, but is not limited to, e-mails or other equivalent evidence.

Revision History

Effective Date	Description
2015-09-01	Initial release.

FAC–001–AB–0 Facility Connection Requirements

1. Purpose

The purpose of this *reliability standard* is to establish connection and performance requirements for *facilities* connecting to the *AIES*.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must document transmission *interconnection* requirements to comply with all *reliability standards*. The *ISO's* transmission *interconnection* requirements must address connection requirements for:

R1.1 Generating units

R1.2 *Transmission facilities*

R1.3 *Transmission connected end-use customer's facilities*

R2 The *ISO's* transmission *interconnection* requirements or project functional specification must address, but is not limited to, the following items:

R2.1 Voltage level and *MW* and *MVAR* capacity or *demand* at point of connection

R2.2 Breaker duty and *surge* protection

R2.3 *System* protection and coordination

R2.4 Metering and telecommunications

R2.5 Grounding and safety issues

R2.6 Insulation and insulation coordination

R2.7 Voltage, *reactive power*, and *power factor* control

R2.8 Power quality impacts

R2.9 Equipment *ratings*

R2.10 Synchronizing of *facilities*

R2.11 Maintenance coordination

R2.12 Operational issues (abnormal frequency and voltages)

R2.13 Inspection requirements for existing or new *facilities*

R2.14 Communications and procedures during normal and emergency operating conditions

R3 The *ISO* must assess the long term implications to the AIES of any facility to be connected to it.

R4 The *ISO* must maintain and update as required and post on its website its transmission *interconnection* requirements.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 The *ISO* transmission *interconnection* requirements include requirements for generating units, *transmission facilities* and *transmission connected end use customer facilities*.

The *ISO* transmission *interconnection* requirements include content that is compliant and consistent with all *reliability standards*.

MR2 The *ISO* transmission *interconnection* requirements or project functional specifications contain information addressing each item identified in R2.

MR3 The assessment made in R3 is included in either the transmission *interconnection* requirements or project functional specification.

MR4 The *ISO* transmission *interconnection* requirements are posted on its website.

A revision history for the *ISO* transmission *interconnection* requirements shows that updates were made for each change to *reliability standards*, as appropriate.

Changes to the *ISO* transmission *interconnection* requirements are completed within 12 months of the *Commission* approving a change in the *reliability standards.*

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Effective	Description
2010-09-24	New Issue

FAC–002–AB–0 Coordination of Plans for New Facilities

1. Purpose

The purpose of this *reliability standard* is to demonstrate that proper evaluation of potential *reliability* impacts of new *transmission facilities* to be connected to the *AIES* has occurred.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must retain the documentation of its evaluation of the potential *reliability* impact of the new *transmission facilities* and their connections on the *AIES* for three years after energization.

R2 The *ISO* must provide the documentation referred to in requirement R1 to the *WECC* within 30 calendar *days* of its request, provided such request is made with the three year period referred to in requirement R1.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Documentation exists for the past three years and is made available when requested per R1.

MR2 Confirmation exists that documentation was received if requested.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Effective	Description
2010-03-22	New Issue

FAC-003-AB1-1 Transmission Vegetation Management Program

1. Purpose

The purpose of this *reliability standard* is to improve the *reliability* of electric transmission systems by preventing *outages* from vegetation located on a right-of-way, corridor or other route (collectively "ROW") and minimizing *outages* from vegetation located adjacent to a ROW, maintaining clearances between *transmission facilities* and vegetation on and along a ROW, and reporting vegetation related *outages* of electric transmission systems to the *ISO* and *WECC.*

2. Applicability

This *reliability standard* applies to:

(a) the *legal owner* of a *transmission facility* with *transmission facilities* operated at 200 kV and above and any lower voltage *transmission facilities* designated by the *ISO* as critical to the *reliability* of the *AIES* as identified in Appendix A; provided that *transmission facilities* on ROWs that are assessed and identified on an annual basis not to have vegetation capable of growing higher than 2 meters are excluded; and

(b) the *ISO.*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the *Consolidated Authoritative Document Glossary*.

4. Requirements

R1 Each *legal owner* of a *transmission facility* must prepare a *TVMP*. This program is to be updated at least annually. The *TVMP* must include the objectives, practices, approved procedures, and work specifications [1] of the *legal owner* of a *transmission facility*.

R1.1 The *TVMP* must define a schedule for and the type (aerial or ground) of ROW vegetation inspections. This schedule must be flexible enough to adjust for changing conditions. The inspection schedule must be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the *transmission facilities* of the *legal owner* of a *transmission facility*. The *legal owner* of a *transmission facility* must perform vegetation inspections as identified in the schedule.

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this *reliability standard*, is considered by *NERC* to be an industry best practice.

R1.2 The *TVMP* must identify and document clearances between vegetation and any overhead ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the *legal owner* of a *transmission facility* must establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and must also establish and maintain a set of clearance requirements identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1 Clearance 1 — Each *legal owner* of a *transmission facility* must determine and document appropriate clearance distances to be achieved at the time of vegetation management work based upon local conditions and the expected time frame in which the *legal owner* of a *transmission facility* plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances must be greater than those defined in Clearance 2.

R1.2.2 Clearance 2 — Each *legal owner* of a *transmission facility* must determine and document specific minimum radial clearance distances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum radial clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. Subject to R1.2.2.1 and R1.2.2.2, the documented specific minimum radial clearance distances must be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances must be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances must be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3 All personnel directly involved in the design and implementation of the *TVMP* must hold appropriate qualifications and must have taken appropriate training, as defined by the *legal owner* of a *transmission facility*, to perform their duties.

R1.4 Each *legal owner* of a *transmission facility* must develop mitigation measures to achieve sufficient clearances for the protection of its *transmission facilities*

when it identifies locations on the ROW where it is restricted from attaining Clearance 1 distances.

R1.5 Each *legal owner* of a *transmission facility* must establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line *outage*.

This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2 The *legal owner* of a *transmission facility* must create and implement an annual plan for vegetation management work to ensure the *reliability* of its *transmission facilities*. The plan must describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan must be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the *reliability* of the *AIES*. Adjustments to the plan must be documented as they occur. The plan must include the time required to obtain permissions or permits from landowners or regulatory authorities. Each *legal owner* of a *transmission facility* must have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to its work specifications.

R3 Each *legal owner* of a *transmission facility* must report quarterly to the *ISO*, *sustained outages* to its transmission lines determined by the *legal owner* of a *transmission facility* to have been caused by vegetation.

R3.1 Multiple *sustained outage*s on an individual transmission line, if caused by the same vegetation, must be reported as one *outage* regardless of the actual number of *outages* within a 24-hour period.

R3.2 The *legal owner* of a *transmission facility* is not required to report to the *ISO, sustained outages* to its transmission lines caused by either:

- vegetation falling onto a transmission line from outside the ROW caused by a natural disasters are not considered reportable (examples of disasters include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, ice storms, floods, major storms as defined either by the *legal owner* of a *transmission facility* or an applicable regulatory body); or
- vegetation falling onto a transmission line caused by human or animal activity are not considered reportable (examples of human or animal activity include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural, horticultural or agricultural activities, or removal/digging of vegetation).

R3.3 The *outage* information provided by the *legal owner* of a *transmission facility* to the *ISO* must include at a minimum:

- number or name of the transmission line(s) forced out of service;
- date and time;
- duration of the *outage*;

- description of the cause of the *outage*;
- other pertinent comments; and
- remedial action taken by the *legal owner* of a *transmission facility*.

R3.4 An *outage* must be categorized by the *legal owner* of a *transmission facility* as one of the following:

R3.4.1 Category 1 — Grow-ins: *Outages* caused by vegetation growing into transmission lines from vegetation inside and/or outside of the ROW;

R3.4.2 Category 2 — Fall-ins: *Outages* caused by vegetation falling into transmission lines from inside the ROW; or

R3.4.3 Category 3 — Fall-ins: *Outages* caused by vegetation falling into transmission lines from outside the ROW.

R4 The *ISO* must report quarterly to *WECC*, *sustained outages* to transmission lines determined by the *legal owner* of a *transmission facility* to have been caused by vegetation.

R4.1 Multiple *sustained outages* within a 24-hour period on an individual transmission line, if caused by the same vegetation, must be reported as one *outage* regardless of the actual number of *outages*.

R4.2 The *ISO* is not required to report to *WECC*, *sustained outages* to transmission lines caused by either:

- *outages* from vegetation falling onto transmission lines from outside the ROW caused by natural disasters are not reportable (examples of disasters include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, ice storms, floods, major storms as defined either by the *legal owner* of a *transmission facility,* or an applicable regulatory body); or
- *outages* from vegetation caused by human or animal activity are not considered reportable (examples of human or animal activity include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural, horticultural or agricultural activities, or removal/digging of vegetation).

R4.3 The *outage* information provided by the *ISO* to *WECC* must include at a minimum:

- number or name of the transmission line(s) forced out of service;
- date and time;
- duration of the *outage*;
- description of the cause of the *outage*;
- other pertinent comments; and
- remedial action taken by the *legal owner* of a *transmission facility*.

R4.4 An *outage* must be categorized by the *legal owner* of a *transmission facility* as one of the following:

R4.4.1 Category 1 — Grow-ins: *Outages* caused by vegetation growing into transmission lines from vegetation inside and/or outside of the ROW;

R4.4.2 Category 2 — Fall-ins: *Outages* caused by vegetation falling into transmission lines from inside the ROW; or

R4.4.3 Category 3 — Fall-ins: *Outages* caused by vegetation falling into transmission lines from outside the ROW.

5. Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

These measures will be used by the *ISO* in carrying out its compliance monitoring duties in accordance with *ISO rule* 12. The *ISO* may consider other data and information, including any provided by a *market participant*.

MR1 A revision history of the *TVMP* is provided annually to the *ISO*. A *TVMP* exists and is provided in the format specified in the *ISO TVMP* template. The *TVMP* is provided within 30 *days* of request. The *TVMP* is complete and includes the required component sections specified in the template.

MR1.1 A vegetation inspection schedule exists in the *TVMP*. The schedule is completed in accordance with the *ISO TVMP* template. The schedule includes all applicable transmission lines. Documentation exists to show that the vegetation inspections have been performed.

MR1.2 Clearance 1 and Clearance 2 values exist in the *TVMP*

MR1.2.1 Clearance 1 values exist for every transmission line. Clearance 1 values specified are greater than those of Clearance 2.

MR1.2.2 Clearance 2 values exist for every transmission line. Clearance 2 values specified are greater than the minimum clearances set in IEEE standards for the applicable scenarios.

MR1.3 Requirements, training, and qualifications for positions responsible for preparing and implementing the *TVMP* exist. Documentation exists to confirm that personnel meet the requirements, training, and qualifications of the position. Acceptable documentation includes training records, licenses, certificates, and resumes.

MR1.4 A list exists and specifies locations on the ROW where Clearance 1 is not attainable. Mitigation measures exist where there are restrictions. Mitigating measures are appropriate and meet the intent of this *reliability standard*.

MR1.5 A documented process or procedure for communication exists. The process is appropriate and of sufficient detail to meet the intent of the requirement.

MR2 A work plan exists in the form of the *ISO* vegetation management work plan template. The work plan is complete. The work plan is submitted annually and within 30 *day*s of being requested.

Evidence exists to show that the work plan is implemented. Evidence may include status and inspection reports, work orders, and/or contracts. The work plan is being followed in accordance to the schedule. The work is completed in accordance with the work plan. Revision documentation exists where the plan has been revised. Evidence is provided to the *ISO* within 30 *day*s of a request.

MR3 to 3.4.3 Quarterly reports are submitted to the *ISO* by the dates specified by the *ISO*. Quarterly reports contain all sustained outages caused by vegetation for that reporting period. Quarterly reports contain the specific information in the requirement.

MR4 to 4.4.3 Quarterly reports are submitted to the *WECC* by dates specified by *WECC*. Quarterly reports contain all sustained *outages* caused by vegetation received by the *ISO* for that reporting period. Quarterly reports contain the specific information in the requirement.

7. Appendices

Appendix A - Transmission Facilities Designated as Critical to the AIES

The following facilities have been identified as critical to the *AIES* and require the application of this *reliability standard*:

- 887L (Pocaterra T48S - Alberta / BC border);
- 777L (Pocaterra T48S - Seebe T245S);
- 786L (Coleman T799S - Alberta / BC border); and
- 170L (Coleman T799S - Pincher Creek T396S).

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date	Description
2012-12-17	Administrative update – "*TFO*" replaced with the "*legal owner* of a *transmission facility*"; and other minor cleanup items.
2010-01-26	R1 and R2
2013-10-01	New Issue

Alberta Reliability Standard
System Operating Limits Methodology for the Planning Horizon
FAC-010-AB1-2.1

1. Purpose

The purpose of this **reliability standard** is to ensure that **system operating limits** used in the reliable planning of the **bulk electric system** are determined based on an established methodology or methodologies.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must have a documented **system operating limit** methodology for use in developing **system operating limits** that:

(a) is applicable for developing **system operating limits** used in the **ISO**'s planning horizon;

(b) states that **system operating limits** must not exceed any associated **facility rating**; and

(c) includes a description of how to identify the subset of **system operating limits** that qualify as **interconnected reliability operating limits**.

R2 The **system operating limit** methodology of the **ISO** must include a requirement:

R2.1 That **system operating limits** developed in the pre-**contingency** state, and with all facilities in service:

(a) result in:

i. **bulk electric system** performance that demonstrates transient, dynamic and voltage stability;

ii. all facilities operating within their **facility ratings**; and

iii. system conditions within thermal, voltage and stability limits;

and

(b) reflect expected system conditions and changes to **bulk electric system** topology.

R2.2 That **system operating limits** developed starting with all facilities in service and following any single **contingency** including:

(a) single line to ground **fault** or three-phase **fault**, whichever is most severe, with **normal clearing**, on any **generating unit**, line, transformer or shunt device;

(b) loss of any **generating unit**, line, transformer or shunt device without a **fault**; or

(c) single pole block, with **normal clearing**, in a monopolar or bipolar high voltage direct current system;

result in **bulk electric system** performance that:

(d) demonstrates transient, dynamic and voltage stability;

(e) has all facilities operating within their **facility ratings**;

(f) is within voltage and stability limits; and

(g) has no **cascading** or uncontrolled separation,

with either or both of the following responses to the single **contingency** being acceptable:

(h) planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the facility on which the **fault** occurred or by the affected area; or

(i) **bulk electric system** reconfiguration through manual or automatic control or protection actions.

R2.3 Intentionally left blank.

R2.4 That following a single **contingency**, in preparation for the next **contingency** when developing **system operating limits**, the **ISO** may make system adjustments, including changes to generation, uses of the **transmission system**, and the **transmission system** topology.

R2.5 That **system operating limits** developed starting with all facilities in service and following any of the multiple **contingencies** identified in **reliability standard** TPL-003-AB, result in **bulk electric system** performance that:

(a) demonstrates transient, dynamic and voltage **stability**;

(b) has all facilities operating within their **facility ratings**;

(c) is within voltage and stability limits; and

(d) has no **cascading** or uncontrolled separation,

with any of the following responses to such multiple **contingencies** being acceptable:

(e) planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the facility on which the **fault** occurred or by the affected area;

(f) **bulk electric system** reconfiguration through manual or automatic control or protection actions; or

(g) planned or controlled interruption of **demand** to **demand customers**, the planned removal of a **generating unit**, or the curtailment of firm, non-recallable power transfers.

R2.6 Intentionally left blank.

R3 In addition to requirements R1 through R2, the **ISO** must include within the **system operating limit** methodology a description of the:

(a) study model, which must include at least the Alberta system as well as the critical modeling details from other interconnected jurisdictions that would impact any facility under study;

(b) selection of applicable **contingencies**;

(c) level of system detail included in the study model used to determine **system operating limits**;

(d) allowed uses of **remedial action schemes**;

(e) anticipated **transmission system** configuration, generation **dispatch** and **load** level;

(f) criteria for determining when violating a **system operating limit** qualifies as an **interconnection reliability operating limit** and criteria for developing any associated **interconnection reliability operating limit** T_V; and

(g) any reliability margins applied.

R4 The **ISO** must provide its **system operating limit** methodology, and any update to that methodology, to all of the following prior to implementation of the methodology or any update to the methodology:

(a) each adjacent planning authority; and

(b) each planning authority that indicated it has a **reliability**-related need for the methodology.

R5 Intentionally left blank.

R6 The **system operating limit** methodology of the **ISO** must include a requirement that:

R6.1 for **interconnections** with other systems within the **WECC**, starting with all facilities in service and following any of the multiple **contingencies** identified in **reliability standard** TPL-003-AB or any of the following multiple **contingencies**:

(a) simultaneous permanent phase to ground **faults** of each of two (2) adjacent transmission circuits on a multiple circuit tower with **normal clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five (5) towers at each station, this condition is an acceptable risk and therefore can be excluded;

(b) a permanent phase to ground **fault** on any **generating unit**, transmission circuit, transformer, or **collector bus** section with delayed **fault** clearing except for **collector bus** sectionalizing breakers or **collector bus** tie breakers as specified in requirement R6.2;

(c) simultaneous permanent loss of both poles of a direct current bipolar facility without an alternating current **fault**;

(d) the failure of a circuit breaker associated with a remedial action scheme to operate when required following the loss of any **system element** without a **fault**, or a permanent phase to ground **fault**, with **normal clearing**, on any transmission circuit, transformer or **collector bus** section; or

(e) a single-line-to-ground **fault** with **normal clearing** on common mode **contingency** of two (2) adjacent circuits on separate towers unless the **ISO** determines the event frequency is less than one (1) in thirty (30) years,

the **system operating limits** result in **bulk electric system** performance that:

(f) demonstrates transient, dynamic and voltage **stability**;

(g) has all facilities operating within their **facility ratings**;

(h) is within voltage and stability limits; and

(i) has no **cascading** or uncontrolled separation,

with any of the following responses to such multiple **contingencies** being acceptable:

(j) planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the facility on which the **fault** occurred or by the affected area;

(k) **bulk electric system** reconfiguration through manual or automatic control or protection actions; or

(l) planned or controlled interruption of **demand** to **demand customers**, the planned removal of a **generating unit**, or the curtailment of firm, non-recallable power transfers.

R6.2 for **interconnections** with other systems within the **WECC**, starting with all facilities in service and following either of these multiple **contingencies**:

(a) a common mode **outage** of two (2) **generating units** connected to the same switchyard not otherwise addressed by **reliability standard** FAC-010-AB; or

(b) the loss of multiple **collector bus** sections as a result of failure or delayed clearing of a **collector bus** tie or **collector bus** sectionalizing breaker to clear a permanent phase to ground **fault**, the **system operating limits** result in **bulk electric system** performance such that **cascading** does not occur on other systems in other jurisdictions within the **WECC**.

R6.3 where the **ISO** makes changes to any **contingencies** and required responses identified in requirements R6.1 and R6 .2 for specific facilities on **interconnections** to other systems within the **WECC** in accordance with the **WECC** performance category adjustment process based upon system performance and robust design, the **system operating limits** result in **bulk electric system** performance that satisfies the performance requirements in requirements R2.4.

4. Measures

The following measures correspond to the requirements identified in Section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of having a documented **system operating limit** methodology as required in requirement R1 exists.

MR2 Evidence of the **system operating limit** methodology including requirements as required in sub requirements R2.1, R2.2, R2.4 and R2.5 exists.

MR3 Evidence of the **system operating limit** methodology including the description(s) as required in requirement R3 exists.

MR4 Evidence of providing the **system operating limit** methodology as required in requirement R4 exists. Evidence may include, but is not limited to, email or mail to an appropriate recipient that identifies contents submitted.

MR5 Intentionally left blank.

MR6 Evidence of the **system operating limit** methodology including requirements as required in sub requirements R6.1 through R6.3 exists.

Revision History

Effective	Description
2012-07-01	Initial Release
2015-09-01	Revised for ISO assumption of RC functionality for the Alberta footprint
2016-08-30	Inclusion of the defined term **system element**.

Alberta Reliability Standard

System Operating Limits Methodology for the Operations Horizon

FAC-011-AB-2

1. Purpose

To ensure that **system operating limits** used in the reliable operation of the **bulk electric system** are determined based on an established methodology or methodologies.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must have a documented methodology for use in developing **system operating limits** (**system operating limit** methodology) within its area. This **system operating limit** methodology must:

R1.1 be applicable for developing **system operating limits** used in the operations horizon;

R1.2 state that **system operating limits** must not exceed associated **facility ratings**; and

R1.3 include a description of how to identify the subset of **system operating limits** that qualify as **interconnection reliability operating limits**.

R2 The **system operating limit** methodology of the **ISO** must include a requirement that **system operating limits** provide **bulk electric system** performance consistent with the following:

R2.1 in the **pre-contingency** state, the **bulk electric system** must demonstrate transient, dynamic and voltage stability; all facilities must be within their **facility ratings** and within their thermal, voltage and stability limits. In the determination of **system operating limits**, the **bulk electric system** condition used must reflect current or expected system conditions and must reflect changes to system topology such as facility outages;

R2.2 following the single **contingencies**[1] identified in requirement 2.2.1 through requirement 2.2.3, the system must demonstrate transient, dynamic and voltage stability; all facilities must be operating within their **facility ratings** and within their thermal, voltage and stability limits; and **cascading** or uncontrolled separation must not occur:

R2.2.1 single line to ground or three (3) -phase **fault** (whichever is more severe), with **normal clearing**, on any **generating unit**, **aggregated generating facility**, line, transformer, or shunt device that is **faulted**;

[1] The **contingencies** identified in FAC-011-AB-2 requirement R2.2.1 through requirement R2.2.3 are the minimum **contingencies** that must be studied but are not necessarily the only **contingencies** that are studied.

R2.2.2 loss of any **generating unit**, **aggregated generating facility**, line, transformer, or shunt device without a **fault**; and

R2.2.3 single pole block, with **normal clearing**, in a monopolar or bipolar high voltage direct current system;

R2.3 in determining the system's response to a single **contingency**, the following will be acceptable:

R2.3.1 planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the **faulted** facility or by the affected area;

R2.3.2 interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the **real-time** operating conditions are more adverse than anticipated in the corresponding studies; and

R2.3.3 system reconfiguration through manual or automatic control or protection actions; and

R2.4 to prepare for the next **contingency**, system adjustments may be made, including changes to generation, uses of the **transmission system**, and the **transmission system** topology.

R3. The **ISO**'s methodology for determining **system operating limits**, must include, as a minimum, a description of the following, along with any **reliability** margins applied for each:

R3.1. study model (must include at least the entire **ISO** area as well as the critical modeling details from other **reliability coordinator areas** that would impact the facility or facilities under study);

R3.2. selection of applicable **contingencies**;

R3.3. a process for determining which of the stability limits associated with the list of multiple **contingencies** (as determined by the **ISO** in accordance with FAC-014 requirement R6) are applicable for use in the operating horizon given the actual or expected system conditions;

R3.3.1. this process must address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple **contingencies**;

R3.4. level of detail of system models used to determine **system operating limits**;

R3.5. allowed uses of remedial action schemes or remedial action plans;

R3.6. anticipated **transmission system** configuration, generation **dispatch** and load level; and

R3.7. criteria for determining when violating a **system operating limit** qualifies as an **interconnection reliability operating limit** and criteria for developing any associated **interconnection reliability operating limit Tv**.

R4. The **ISO** must issue its **system operating limit** methodology and any changes to that methodology, prior to the effective date of the methodology or of a change to the methodology, to all of the following:

R4.1. each adjacent **reliability coordinator** and each **reliability coordinator** that indicated it has a reliability-related need for the methodology.

R4.2. each **planning authority** and **transmission planner** that models any portion of the **ISO**'s area.

R4.3. each **operator** of a **transmission facility** that operates in the **ISO**'s area.

R5. Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 The **system operating limit** methodology of the **ISO** may address all of the items listed in requirement R1.1 through requirement R1.3. Evidence may include, but is not limited to, a documented **system operating limit** methodology, or other equivalent evidence as required in requirement R1.

MR2 Evidence of including requirements in the **system operating limit** methodology as set out in requirement R2. Evidence may include, but is not limited to, a documented **system operating limit** methodology, or other equivalent evidence as set out in requirement R2.

MR3 Evidence of including all of the items as required in requirement R3.1 through R3.7 in the **system operating limit** methodology. Evidence may include, but is not limited to, a documented **system operating limit** methodology, documented processes or other equivalent evidence as required in requirement R2.

MR4 The **ISO** may have evidence of issuing the **system operating limit** methodology, and any changes to that methodology, including the date they were issued, as required in requirement R4. Evidence may include, but is not limited to, emails, or other equivalent evidence.

MR5 Intentionally left blank.

Revision History

Date	Description
2015-09-01	Initial release.

Alberta Reliability Standard
Establish and Communicate System Operating Limits
FAC-014-AB1-2

1. Purpose

The purpose of this **reliability standard** is to establish and communicate **system operating limits** to be used in the reliable planning and operation of the **bulk electric system**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must ensure that **system operating limits**, including **interconnection reliability operating limits**, for its area are established and that the **system operating limits** (including **interconnection reliability operating limits**) are consistent with its **system operating limit** methodology.

R2 Intentionally left blank.

R3 Intentionally left blank.

R4 Intentionally left blank.

R5 The **ISO** must provide its **system operating limits** and **interconnection reliability operating limits** in the operating horizon to:

(a) each adjacent **reliability coordinator**;

(b) each **operator** of a **transmission facility** within its area that has a **reliability**-related need for those limits; and

(c) each entity that has a **reliability**-related need for those limits and provides a written request for delivery of those limits.

R5.1 For each **interconnection reliability operating limit**, the **ISO** must provide the following supporting information:

R5.1.1 identification and status of the associated **system element** (or group of **system elements**) that is (are) critical to the derivation of the **interconnection reliability operating limit**;

R5.1.2 the value of the **interconnection reliability operating limit** and its associated Tv;

R5.1.3 the associated **contingency**(ies); and

R5.1.4 the type of limitation represented by the **interconnection reliability operating limit** (e.g., voltage collapse, angular stability).

R5.2 Intentionally left blank.

R5.3 The **ISO** must provide its **system operating limits** (including the subset of **system operating limits** that are **interconnection reliability operating limits**) in the planning horizon to adjacent **planning authorities.**

R5.4 Intentionally left blank.

R6 The **ISO** must identify and develop a list of the subset of multiple **contingencies** from **reliability standard** TPL-003-AB, which result in stability limits as determined if any that exist in its planning horizon.[1]

R6.1 Intentionally left blank.

R6.2 Intentionally left blank.

4 Measures

The following measures correspond to the requirements identified in Section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence that the **ISO**'s **system operating limits**, including **interconnection reliability operating limits**, for its area are established and consistent with its **system operating limit** methodology. Evidence may include, but is not limited to, dated reports, voice recordings, business practices or other equivalent evidence.

MR2 Intentionally left blank.

MR3 Intentionally left blank.

MR4 Intentionally left blank.

MR5 Evidence to confirm the **ISO** provided its **system operating limits** and **interconnection reliability operating limits** and supporting information as required in requirement R5 exists. Evidence may include, but is not limited to, records of email communication to appropriate recipients that identify contents submitted, or other equivalent evidence.

MR6 Evidence that the **ISO** identified and listed the subset of multiple **contingencies** as required in requirement R6 exists. Evidence may include, but is not limited to, dated reports, letters, or other documentation containing the list of multiple **contingencies**.

MR6.1 Intentionally left blank.

MR6.2 Intentionally left blank.

5. Appendices

No appendices have been defined for this **reliability standard**.

Revision History

Date	Description
2016-08-30	Inclusion of the defined term **system element**.
2015-09-01	Revised for ISO assumption of RC functionality for the Alberta footprint
2012-10-01	Initial Release

[1] Requirement R6 is referenced in requirement R3.3 of FAC-011-AB

Alberta Reliability Standard
Transmission Maintenance
FAC-501-WECC-AB2-1

1. Purpose

The purpose of this **reliability standard** is to ensure the **legal owner** of a **transmission facility** of a major transmission path, including any associated **transmission facility**, has a *Transmission Maintenance and Inspection Plan* such that a reliable path is available.

2. Applicability

This **reliability standard** applies to the **legal owner** of a **transmission facility** that is, or is part of, a major transmission path identified in the table "*Major WECC Transfer Paths in the Bulk Electric System*" as provided by the **WECC**.

3. Requirements

R1 The *Transmission Maintenance and Inspection Plan* of the **legal owner** of a **transmission facility** must detail its inspection and maintenance requirements and must apply to each **transmission facility** that is associated with each of the transmission paths identified by the **ISO**.

R1.1 The **legal owner** of a **transmission facility** must review its *Transmission Maintenance and Inspection Plan* annually and update it as required.

R1.2 The **legal owner** of a **transmission facility** must annually submit its *Transmission Maintenance and Inspection Plan* and any updates to the **ISO**.

R2 The *Transmission Maintenance and Inspection Plan* of the **legal owner** of a **transmission facility** must include without limitation the following maintenance categories:

R2.1 Transmission line maintenance details:

R.2.1.1 patrol/inspection;

R.2.1.2 contamination control; and

R.2.1.3 tower and wood pole structure management;

R2.2 Station maintenance details:

R.2.2.1 inspections;

R.2.2.2 contamination control; and

R.2.2.3 equipment maintenance for the following:

(a) circuit breakers;

(b) power transformers (including phase-shifting transformers);

(c) regulators; and

(d) **reactive power** devices (including, but not limited to, shunt capacitors, series capacitors, static VAR compensators, synchronous condensers, shunt reactors, and tertiary reactors).

R3 The maintenance practices of the **legal owner** of a **transmission facility** in the *Transmission Maintenance and Inspection Plan* must be either performance-based, time-based, or condition-based, or a combination of all three (3).

The *Tranmsision Maintenance and Inspection Plan* of the **legal owner** of a **transmission facility** must include scheduled intervals for any time-based maintenance activities and/or a description supporting condition or performance-based maintenance practices including a description of the condition or performance based trigger.

R4 The **legal owner** of a **transmission facility** must implement its *Transmission Maintenance and Inspection Plan* and retain records that demonstrate such implementation including without limitation the following:

R4.1 The names of individual or crew members responsible for performing the work or inspection;

R4.2 The date(s) the work or inspection was performed;

R4.3 The **transmission facility** on which the work or inspection was performed; and

R4.4 A description of the inspection or maintenance performed.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 A documented *Transmission Maintenance and Inspection Plan* as identified in requirement R1 exists and covers each **transmission facility** as identified by the **ISO**.

MR1.1 Evidence exists that shows the **legal owner** of a **transmission facility** reviewed their *Transmission Maintenance and Inspection Plan* annually and updated it as needed.

MR1.2 The *Transmission Maintenance and Inspection Plan* and updates, if any, are received by the **ISO** annually.

MR2 The *Transmission Maintenance and Inspection Plan* addresses the required maintenance details of requirement R2.

MR3 The *Transmission Maintenance and Inspection Plan* addresses the items in requirement R3.

MR4 Records exist that show the **legal owner** of a **transmission facility** implemented and followed its*Transmission Maintenance and Inspection Plan* .

Revision History

Effective	Description
2015-07-01	Transmission paths identified by the AESO for the purposes of requirement R1 updated to include new Bennett 520S equipment and 632 Russell equipment and moved from the Appendix to another document. Administrative update to standardize formatting, definitions and drafting style.
2012-12-17	Administrative update – "*TFO*" replaced with "*legal owner* of a *transmission facility*"; and other minor clean up items.
2010-09-10	Initial Release

Alberta Reliability Standard
Evaluation of Interchange Transactions
INT-006-AB-4

1. Purpose

The purpose of this **reliability standard** is to ensure that responsible entities conduct a **reliability** assessment of each **arranged interchange** before it is implemented.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must approve or deny each on-time **arranged interchange** or emergency **arranged interchange** that it receives and must do so prior to the expiration of the time period defined in Appendix 1, column B.

R1.1 The **ISO** must, when it is either the source **balancing authority** or sink **balancing authority** deny the **arranged interchange** or curtail **confirmed interchange** if it does not expect to be capable of supporting the magnitude of the **interchange**, including ramping, throughout the duration of the **arranged interchange**.

R1.2 The **ISO** must deny the **arranged interchange** or curtail **confirmed interchange** if the **scheduling path** (proper connectivity of **adjacent balancing authorities**) between it and its **adjacent balancing authorities** is invalid.

R2 The **ISO** must approve or deny each on-time **arranged interchange** or emergency **arranged interchange** that it receives and must do so prior to the expiration of the time period defined in Appendix 1, column B.

R2.1 The **ISO** must deny the **arranged interchange** or curtail **confirmed interchange** if the transmission path (proper connectivity of adjacent transmission service providers) between it and its adjacent transmission service providers is invalid.

R3 The **ISO** must, when it receives a **reliability** adjustment **arranged interchange**, approve or deny it prior to the expiration of the time period defined in Appendix 1, column B.

R4 The **ISO** must when it is a sink **balancing authority** confirm that none of the following conditions exist prior to transitioning an **arranged interchange** to **confirmed interchange**:

(a) it is a **reliability** adjustment **arranged interchange**, the time period specified in Appendix 1, column B has elapsed, and the **ISO** or the source **balancing authority** associated with the **arranged interchange** has not communicated its approval of the transition;

(b) it is not a **reliability** adjustment **arranged interchange**, the time period specified in Appendix 1, column B, has elapsed, and not all **balancing authorities** and transmission service providers associated with the **arranged interchange** have communicated their approval of the transition; or

(c) it is not a **reliability** adjustment **arranged interchange**, the time period specified in Appendix 1, column B, has elapsed, and any entity associated with the **arranged interchange** has communicated its denial of the transition.

R5 For each **arranged interchange** that is transitioned to **confirmed interchange**, the **ISO** must, when it is the sink **balancing authority**, notify the following entities of the on-time **confirmed interchange** such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Appendix 1, column D:

R5.1 the source **balancing authority**;

R5.2 each intermediate **balancing authority**;

R5.3 each **reliability coordinator** associated with each **balancing authority** included in the **arranged interchange**;

R5.4 each transmission service provider included in the **arranged interchange**; and

R5.5 each purchasing selling entity included in the **arranged interchange**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence of either approving or denying **arranged interchange** as required in requirement R1 exists. Evidence may include, but is not limited to, dated and time stamped electronic logs or other equivalent evidence.

MR2 Evidence of either approving or denying **arranged interchange** as required in requirement R2 exists. Evidence may include, but is not limited to, dated and time stamped electronic logs or other equivalent evidence.

MR3 Evidence of either approving or denying **reliability** adjustment **arranged interchange** as required in requirement R3 exists. Evidence may include, but is not limited to, dated and time stamped electronic logs, studies or other equivalent evidence.

MR4 Evidence of confirming none of the conditions exist prior to transitioning an **arranged interchange** to **confirmed interchange** as required in requirement R4 exists. Evidence may include, but is not limited to, an interchange transaction without an implemented e-tag, or other equivalent evidence.

MR5 Evidence of notifying entities of the on-time **confirmed interchange** as required in requirement R5 exists. Evidence may include, but is not limited to, dated and time stamped electronic logs, voice recordings or other equivalent evidence.

5. Appendices

Appendix 1 – Timing Tables

Revision History

Date	Description
2018-10-01	Initial release.

Appendix 1 – Timing Tables
Timing Requirements for WECC

		A	B	C	D
If **arranged interchange**[1] is submitted	Time Classification	Sink BA makes initial distribution of **arranged interchange**[2]	BA and TSP conduct reliability assessments	Compilation and distribution status[2]	BA prepares **confirmed interchange** for implementation
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		N/A
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of **confirmed interchange**
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of **confirmed interchange**
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from **arranged interchange** receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from **arranged interchange** receipt		≥ 3 minutes prior to ramp start
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from **arranged interchange** receipt		≥ 3 minutes prior to ramp start

[1] Time classifications and deadlines apply to both initial **arranged interchange** submittal and any subsequent modifications to the **arranged interchange**.
[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If **arranged interchange**[1] is submitted	Time Classification	Sink BA makes initial distribution of **arranged interchange**[2]	BA and TSP conduct reliability assessments	Compilation and distribution status[2]	BA prepares **confirmed interchange** for implementation
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from **arranged interchange** receipt		≥ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from **arranged interchange** receipt		≥ 3 minutes prior to ramp start
< 1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from **arranged interchange** receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from **arranged interchange** receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from **arranged interchange** receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the **arranged interchange** was recieved		≥ 1 hour 58 minutes prior to ramp start

Alberta Reliability Standard
Implementation of Interchange
INT-009-AB-2.1

1. Purpose

The purpose of this **reliability standard** is to ensure that **balancing authorities** implement the **interchange** as agreed upon in the **interchange** confirmation process.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must agree with each of its **adjacent balancing authorities** that its composite **confirmed interchange** with that **adjacent balancing authority**, at mutually agreed upon time intervals, excluding **dynamic schedules** and pseudo-ties and including any **interchange** per INT-010-AB not yet captured in the **composite confirmed interchange**, is:

R1.1 identical in magnitude to that of the **adjacent balancing authority**; and

R1.2 opposite in sign or direction to that of the **adjacent balancing authority**.

R2 The **ISO** when it is either the attaining **balancing authority** or the native **balancing authority** must use a dynamic value emanating from a common source that is agreed upon with the other **balancing authority** to account for the pseudo-tie in the **net actual interchange** term of its control **area control error** or alternate control process.

R3 The **ISO** must, if it is the **balancing authority** in whose area the high-voltage direct current **intertie** is controlled, coordinate the **confirmed interchange** prior to its implementation with the **operator** of the high-voltage direct current **intertie**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence of agreeing on composite **confirmed interchange** with **adjacent balancing authorities** as required in requirement R1 exists. Evidence may include, but is not limited to dated logs, voice recordings, electronic records or other equivalent evidence.

MR2 Evidence of using a dynamic value emanating from an agreed upon common source as required in requirement R2 exists. Evidence may include, but is not limited to dated logs, voice recordings, electronic records, written agreement or other equivalent evidence.

MR3 Evidence of coordinating the **confirmed interchange** prior to its implementation with the **operator** of the high-voltage direct current **intertie** as required in requirement R3 exists. Evidence may include, but is not limited to dated logs, electronic records or other equivalent evidence.

Revision History

Date	Description
2018-10-01	Initial release.

Alberta Reliability Standard
Interchange Initiation and Modification for Reliability
INT-010-AB-2.1

1. Purpose

The purpose of this **reliability standard** is to provide guidance for required actions on **confirmed interchange** or **implemented interchange** to address **reliability**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must, if it experiences a loss of resources covered by an energy sharing agreement or other **reliability** needs covered by an energy sharing agreement, ensure that a request for **interchange** is submitted with a start time no more than sixty (60) minutes beyond the resource loss or **reliability** need. If the use of the energy sharing agreement does not exceed sixty (60) minutes from the time of the resource loss or **reliability** need, no request for **interchange** is required.

R2 The **ISO** must, when it is the sink **balancing authority**, after modifying a **confirmed interchange** or **implemented interchange** for actual or anticipated **reliability**-related reasons, ensure that a **reliability** adjustment **arranged interchange** reflecting the modification is submitted within sixty (60) minutes of the start of the modification.

R3 The **ISO** must, when it is a sink **balancing authority**, after scheduling **interchange** for actual or anticipated **reliability**-related reasons, ensure that a request for **interchange** is submitted reflecting that **interchange schedule** within sixty (60) minutes of the start of the scheduled **interchange**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence of ensuring that a **request for interchange** is submitted as required in requirement R1 exists. Evidence may include, but is not limited to, dated and time-stamped request for **interchange**, electronic logs or other equivalent evidence.

MR2 Evidence of ensuring that a **reliability** adjustment **arranged interchange** is submitted as required in requirement R2 exists. Evidence may include, but is not limited to, dated and time-stamped **reliability** adjustment **arranged interchange**, electronic logs or other equivalent evidence.

MR3 Evidence of ensuring that a **reliability** adjustment **arranged interchange** is submitted as required in requirement R2 exists. Evidence may include, but is not limited to, dated and time-stamped **reliability** adjustment **arranged interchange**, electronic logs or other equivalent evidence.

Revision History

Date	Description
2018-10-01	Initial release.

Alberta Reliability Standard
Reliability Coordination – Responsibility and Authorities
IRO-001-AB1-1.1

1. Purpose

The **ISO** must have the authority, plans, and agreements in place to immediately direct entities within its area to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If the **ISO** delegates tasks to others, the **ISO** retains its responsibilities for complying with **reliability standards**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 Intentionally left blank.

R2 The **ISO** must develop a reliability plan for its area.

R3 Intentionally left blank.

R4 If the **ISO** delegates reliability coordination-type tasks to other Alberta entities, it must have formal operating agreements with each entity to which tasks are delegated. The **ISO** must verify that all delegated tasks are understood, communicated, and addressed within its area. All responsibilities for complying with **reliability standards** applicable to the **ISO** will remain with the **ISO**.

R5 The **ISO** must list within its reliability plan all Alberta entities to which the **ISO** has delegated reliability coordination-type required tasks.

R6 The **ISO** must verify that all delegated reliability coordination-type tasks are carried out by NERC-certified **reliability coordinator** operating personnel.

R7 The **ISO** must have clear, comprehensive coordination agreements with adjacent **reliability coordinators** to ensure that **system operating limit** or **interconnection reliability operating limit** violation mitigation requiring actions in adjacent **reliability coordinator areas** are coordinated.

R8 Intentionally left blank.

R9 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Intentionally left blank.

MR2 Evidence of developing a reliability plan in accordance with requirement R2 may include, but is not limited to, a dated, current reliability plan.

MR3 Intentionally left blank.

MR4 If the **ISO** has delegated reliability coordination-type tasks to other entities, the **ISO** may have current formal operating agreements with entities that have been delegated such tasks in accordance with requirement R4.

The **ISO** may also have evidence that could include, but is not limited to, job descriptions, signed agreements, records of training sessions, monitoring procedures or other equivalent evidence that will be used to confirm that all reliability coordination-type tasks that have been delegated to other entities are understood, communicated, and addressed within its area in accordance with requirement R4.

MR5 Evidence of the list within the **ISO**'s reliability plan may include, but is not limited to, a list within the documented reliability plan or other equivalent evidence, in accordance with requirement R5.

MR6 The **ISO** may have evidence that could include, but is not limited to, records that show each operating person assigned to perform a delegated reliability coordination-type task has a NERC **reliability coordinator** certification credential, or equivalent evidence confirming that delegated tasks were carried out by NERC-certified **reliability coordinator** operating personnel, as specified in requirement R6.

MR7 The **ISO** may have as evidence signed agreements with adjacent **reliability coordinators** that will be used to confirm that the **ISO** will coordinate corrective actions in the event **system operating limit** and **interconnection reliability operating limit** mitigation actions within adjacent **reliability coordinator areas** must be taken.

MR8 Intentionally left blank.

MR9 Intentionally left blank.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Reliability Coordination - Facilities
IRO-002-AB-2

1. Purpose

The **ISO** needs information, tools and other capabilities to perform its responsibilities.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must have adequate communications facilities (voice and data links) to appropriate entities within its area. These communications facilities must be staffed and available to act in addressing a real-time emergency condition.

R2 The **ISO** must provide, or arrange provisions for, data exchange to **reliability coordinators** or **transmission operators** and **balancing authorities** via a secure network.

R3 The **ISO** must have multi-directional communications capabilities with each **operator** of a **transmission facility** within the **interconnected electric system**, and with neighboring **reliability coordinators**, for both voice and data exchange as required to meet reliability needs of the **Interconnection**.

R4 The **ISO** must have detailed real-time monitoring capability of its area and sufficient monitoring capability of its surrounding areas to ensure that potential or actual **system operating limit** or **interconnection reliability operating limit** violations are identified. The **ISO** must have monitoring systems that provide information that can be easily understood and interpreted by the **ISO**'s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.

R5 The **ISO** must monitor **system elements** of the **bulk electric system** that could result in **system operating limit** or **interconnection reliability operating limit** violations within its area. The **ISO** must monitor both **real power** and **reactive power** system flows, and **operating reserves**, and the status of **system elements** of the **bulk electric system** that are or could be critical to **system operating limit** s and **interconnection reliability operating limit** s and system restoration requirements within its area.

R6 The **ISO** must have adequate analysis tools such as state estimation, pre and post-contingency analysis capabilities (thermal, stability, and voltage), and **wide-area** overview displays.

R7 The **ISO** must continuously monitor its area. The **ISO** must have provisions for backup facilities that must be exercised if the main monitoring system is unavailable. The **ISO** must ensure **system operating limit** or **interconnection reliability operating limit** monitoring and derivations continue if the main monitoring system is unavailable.

R8 The **ISO** must control its analysis tools (referred to in requirement R6), including approvals for planned maintenance. The **ISO** must have procedures in place to mitigate the effects of analysis tool outages.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Evidence may include, but is not limited to, a document that lists communications facilities (voice and data links) with applicable entities within its area.

Evidence of having personnel available to act in addressing a real-time emergency condition as required in requirement R1 exists. Evidence may include, but is not limited to, shift schedules.

MR2 Evidence of providing or arranging provisions as required in requirement R2 exists. Evidence may include, but is not limited to, network description documentation.

MR3 The **ISO** may have evidence that could include, but is not limited to, a document that lists multi-directional communications facilities with each **operator** of a **transmission facility** and with neighboring **reliability coordinators**, that will be used to confirm that it has multi-directional communications facilities, for both voice and data exchange, in accordance with requirement R3.

MR4 The **ISO** may have evidence that could include, but is not limited to, energy management system description documents, computer printouts, SCADA data collection system communications performance or equivalent evidence to demonstrate that it has real-time monitoring capability of its area and monitoring capability of its surrounding areas to identify potential or actual **system operating limit** or **interconnection reliability operating limit** violations.

MR5 Evidence of monitoring **bulk electric system elements** and both **real power** and **reactive power** system flows, and **operating reserves**, and the status of **system elements** of the **bulk electric system** as required in requirement R5 exists. Evidence may include, but is not limited to, SCADA displays, single line diagram print screens or other equivalent evidence.

MR6 The **ISO** may have evidence that could include, but is not limited to, EMS displays, or other equivalent evidence to show that it has analysis tools in accordance with requirement R6.

MR7 The **ISO** may have evidence such as equipment documentation, operating procedures, or other equivalent evidence to show that it has a backup monitoring facility that can be used to identify and monitor **system operating limit** s and **interconnection reliability operating limits**.

MR8 The **ISO** may have evidence that could include, but is not limited to, a documented procedure for approval of planned maintenance to analysis tools (referred to in requirement R6).

The **ISO** may have procedures that are used to mitigate the effects of analysis tool outages as specified in requirement R8.

Revision History

Effective Date	Description
2015-04-01	Initial release.
2016-08-30	Inclusion of the defined term **system element**.

Alberta Reliability Standard
Reliability Coordination – Wide-Area View
IRO-003-AB-2

1. Purpose

The **ISO** must have a **wide-area** view of its area and neighbouring **reliability coordinator areas**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must monitor all **bulk electric system** facilities, which may include sub-transmission information, within its area and adjacent **reliability coordinator areas**, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the **ISO** is able to determine any potential **system operating limit** and **interconnection reliability operating limit** violations within its area.

R2 The **ISO** must know the current status of all critical facilities whose failure, degradation or disconnection could result in an **system operating limit** or **interconnection reliability operating limit** violation. The **ISO** must also know the status of any facilities that may be required to assist area restoration objectives.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Evidence may include, but is not limited to, energy management system description documents, computer printouts, SCADA data collection, or other equivalent evidence that will be used to confirm that the **ISO** monitors all **bulk electric system** facilities within its area and adjacent **reliability coordinator areas** as necessary to ensure that, regardless of prior planned or unplanned events, it is able to determine any potential **system operating limit** and **interconnection reliability operating limit** violations within its area.

MR2 Evidence may include, but is not limited to, SCADA displays or other equivalent evidence that demonstrates knowledge of the current status of all critical facilities whose failure, degradation or disconnection could result in an **system operating limit** or **interconnection reliability operating limit** violation. Evidence of knowledge of the status of any facilities that may be required to assist area restoration objectives.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Reliability Coordination – Current Day Operations
IRO-005-AB-3.1a

1. Purpose

The **ISO** must be continuously aware of conditions within its area and include this information in its reliability assessments. The **ISO** must monitor **bulk electric system** parameters that may have significant impacts upon its area and neighbouring **reliability coordinator areas**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must monitor parameters in its area, including but not limited to the following:

- **R1.1** current status of **system elements** that are part of the **bulk electric system** (transmission or generation including critical auxiliaries such as **automatic voltage regulators** and **remedial action schemes**) and system loading;
- **R1.2** current pre-contingency **system element** conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate **system operating limit** or **interconnection reliability operating limit** violations, including the plan's viability and scope;
- **R1.3** current post-contingency **system element** conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate **system operating limit** or **interconnection reliability operating limit** violations, including the plan's viability and scope;
- **R1.4** system **real power** and **reactive power** reserves (actual versus required);
- **R1.5** capacity and energy adequacy conditions;
- **R1.6** current **area control error**;
- **R1.7** current local or transmission loading relief procedures in effect;
- **R1.8** planned generation **dispatches**;
- **R1.9** planned transmission or generation outages; and
- **R1.10** **contingency** events.

R2 The **ISO** must monitor parameters in its area to ensure that the required amount of **operating reserves** is provided and available as required to meet the **control performance standard** and **disturbance control standard** requirements. If necessary, the **ISO** must arrange for assistance from neighboring **balancing authorities**. The **ISO** must issue energy emergency alerts as needed.

R3 The **ISO** must ensure that it is aware of geomagnetic disturbance forecast information and develop any required response plans.

R4 Intentionally left blank.

R5 The **ISO** must monitor system frequency and rebalance as necessary to return to **control performance standard** and **disturbance control standard** compliance. The **ISO** must utilize all resources, including issuing directives for firm load shedding, to relieve the emergent condition.

R6 The **ISO** must develop and implement action plans to mitigate anticipated or actual **system operating limit**, **control performance standard** or **disturbance control standard** violations. The **ISO** must coordinate pending transmission maintenance outages with any **operator** of a **transmission facility**, adjacent **transmission operator**, **adjacent balancing authority**, **operator** of a **generating unit** or **operator** of an **aggregated generating facility**, as needed, in both the **real-time** and next-day reliability analysis timeframes.

R7 As necessary, the **ISO** must arrange for assistance from neighboring **reliability coordinator areas** or **balancing authorities**.

R8 Intentionally left blank.

R9 Whenever a **remedial action scheme** that may have an inter-**balancing authority**, or inter-transmission operator / inter-**operator** of a **transmission facility** impact (e.g., could potentially affect transmission flows resulting in a **system operating limit** or **interconnection reliability operating limit** violation) is armed, the **ISO** must be aware of the impact of the operation of that **remedial action scheme** on inter-area flows.

R10 In instances where there is a difference in derived limits, the **ISO** must always operate the **bulk electric system** to the most limiting parameter.

R11 The **ISO** must respect **system operating limits** and **interconnection reliability operating limits** in accordance with regional **total transfer capability** and **available transfer capability** processes.

R12 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 The **ISO** may have evidence that could include, but is not limited to, energy management system description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in requirement R1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors its area parameters specified in requirements R1.1 through R1.9.

MR2 The **ISO** must have evidence of monitoring parameters as required in requirement R2. Evidence may include but is not limited to: voice recordings, operator logs, data files or other equivalent evidence.

MR3 The **ISO** may have evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence to demonstrate that it was aware of geomagnetic disturbance (GMD) forecast information and evidence of the development of any required response plans.

MR4 Intentionally left blank.

MR5 The **ISO** may have evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and rebalanced, as specified in requirement R5.

The **ISO** may have evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including issuing directives for firm load shedding, to relieve an emergent condition.

MR6 The **ISO** may have evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it developed and implemented action plans to mitigate anticipated or actual **system operating limit**, **control performance standards** or **disturbance control standard** violations. The **ISO** may have evidence that could include, but is not limited to, electronic communications, operator logs or equivalent evidence that will determine if it coordinated pending transmission maintenance outages with an **operator** of a **transmission facility**, adjacent **transmission operator**, adjacent **balancing authorities**, **operator** of a **generating unit** or operator of an **aggregated generating facility**.

MR7 The **ISO** may have evidence that could include, but is not limited to, computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the **ISO** arranged for assistance from neighboring **reliability coordinator areas** or **balancing authorities**.

MR8 Intentionally left blank.

MR9 If a **remedial action scheme** is armed and that system could have had an inter-area impact, the **ISO** may have evidence that could include, but is not limited to, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that **remedial action scheme** on inter-area flows.

MR10 If there is an instance where there is a disagreement on a derived limit, the **ISO** may have evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated the **bulk electric system** to the most limiting parameter.

MR11 The **ISO** may have evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the **system operating limits** or **interconnection reliability operating limits** in accordance with regional **total transfer capability** and **available transfer capability** processes.

MR12 Intentionally left blank.

Revision History

Effective Date	Description
2015-04-01	Initial release.
2016-08-30	Inclusion of the defined term **system element**.

Alberta Reliability Standard
Reliability Coordination – Transmission Loading Relief
IRO-006-AB-5

1. Purpose

To ensure coordinated action between **Interconnections** when implementing **Interconnection**-wide transmission loading relief procedures to prevent or manage potential or actual **system operating limit** and **interconnection reliability operating limit** exceedances to maintain reliability of the **bulk electric system**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 When the **ISO** receives a request pursuant to an **Interconnection**-wide transmission loading relief procedure (such as Eastern Interconnection Transmission Loading Relief, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any **reliability coordinator**, **balancing authority**, or **transmission operator** in another **Interconnection** to curtail an **interchange transaction** that crosses an **Interconnection** boundary, the **ISO** must comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 The **ISO** may have evidence (such as dated logs, voice recordings, **e-tag** histories, and studies, in electronic or hard copy format) that, when a request to curtail an **interchange transaction** crossing an **Interconnection** boundary pursuant to an **Interconnection**-wide transmission loading relief procedure was made from another **reliability coordinator**, **balancing authority**, or **transmission operator** in that other **Interconnection**, the **ISO** complied with the request or provided a reliability reason why it could not comply with the request.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Qualified Transfer Path Unscheduled Flow Relief
IRO-006-WECC-AB-2

1. Purpose

The purpose of this **reliability standard** is to mitigate transmission overloads due to unscheduled flow on **qualified transfer paths**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must approve schedule curtailment requests submitted to mitigate transmission overloads on **qualified transfer paths**, implement alternative actions, or a combination thereof that collectively meets the relief requirement.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard.** For example, MR1 is the measure for requirement R1.

MR1 **E-tags**, voice recordings or operator logs exist and are provided on request. **E-tags**, voice recordings or operator logs contain content confirming requirement R1 is met.

Revision History

Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Reliability Coordinator Operational Analysis and Real-time Assessments
IRO-008-AB-1

1. Purpose

To prevent instability, uncontrolled separation, or **cascading** that adversely impact the reliability of the **Interconnection** by ensuring that the **bulk electric system** is assessed during the operations horizon.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must perform an **operational planning analysis** to assess whether the planned operations for the next **day** within its **wide-area** will exceed any of its **interconnection reliability operating limits** during anticipated normal and **contingency** event conditions.

R2 The **ISO** must perform a **real-time assessment** at least once every 30 minutes to determine if its **wide-area** is exceeding any **interconnection reliability operating limits** or is expected to exceed any **interconnection reliability operating limits**.

R3 When the **ISO** determines that the results of an **operational planning analysis** or **real-time assessment** indicate the need for specific operational actions to prevent or mitigate an instance of exceeding an **interconnected reliability operating limit**, the **ISO** must share its results with those entities outside Alberta that are expected to take those actions.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 The **ISO** may have the results of its **operational planning analysis** in accordance with requirement R1.

MR2 The **ISO** may have evidence to show it conducted a **real-time assessment** at least once every 30 minutes, in accordance with requirement R2. This evidence may include, but is not limited to, a dated computer log showing times the assessment was conducted, dated checklists, or other equivalent evidence.

MR3 The **ISO** may have evidence to confirm that it shared the results of its **operational planning analysis** or **real-time assessments** with those entities outside Alberta expected to take actions based on that information in accordance with requirement R3. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated transcripts of voice records, dated facsimiles, or other equivalent evidence.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Reliability Coordinator Actions to Operate Within Interconnection Reliability Operating Limits
IRO-009-AB-1

1. Purpose

To prevent instability, uncontrolled separation, or **cascading** that adversely impact the reliability of the **Interconnection** by ensuring prompt action to prevent or mitigate instances of exceeding **interconnection reliability operating limits**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 For each **interconnection reliability operating limit** that the **ISO** identifies one or more days prior to the current day, the **ISO** must have one or more operating processes, operating procedures, or operating plans that identify actions to take or actions to direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those **linterconnection reliability operating limits**.

R2 For each **interconnection reliability operating limit** that the **ISO** identifies one or more days prior to the current day, the **ISO** must have one or more operating processes, operating procedures, or operating plans that identify actions to take or actions to direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that **interconnection reliability operating limit** such that the **interconnection reliability operating limit** is relieved within the **interconnection reliability operating limit**'s T_V.

R3 When an assessment of actual or expected system conditions predicts that an **interconnection reliability operating limit** in its area will be exceeded, the **ISO** must implement one or more operating processes, operating procedures or operating plans (not limited to the operating processes, operating procedures, or operating plans developed for requirement R1) to prevent exceeding that **interconnection reliability operating limit**.

R4 When actual system conditions show that there is an instance of exceeding an **interconnection reliability operating limit** in its area, the **ISO** must, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that **interconnection reliability operating limit** within the **interconnection reliability operating limit**'s T_V.

R5 If unanimity cannot be reached between a **reliability coordinator** and the **ISO** on the value for an **linterconnection reliability operating limit** or its T_V for a facility (or group of facilities) that is part of an **interconnection** and that both entities are responsible to monitor, the **ISO** must, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Evidence may include but is not limited to a list of any **interconnection reliability operating limits** (and each associated T_V) identified in advance, along with one or more dated operating processes, operating procedures, or operating plans that will be used to confirm that the **ISO**

has operating processes, operating procedures, or operating plans to address both preventing and mitigating instances of exceeding **interconnection reliability operating limits** in accordance with requirement R1.

MR2 Evidence may include but is not limited to a list of any **interconnection reliability operating limits** (and each associated T_V) identified in advance, along with one or more dated operating processes, operating procedures or operating plans that will be used to confirm that the **ISO** has operating processes, operating procedures, or operating plans to address both preventing and mitigating instances of exceeding **interconnection reliability operating limits** in accordance with requirement R2.

MR3 Evidence may include, but is not limited to, operating processes, operating procedures or operating plans from requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence that will be used to confirm that the **ISO** implemented one or more operating processes, operating procedures or operating plans in accordance with requirement R3.

MR4 Evidence may include, but is not limited to, operating processes, operating procedures, or operating plans from requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence that will be used to confirm that the **ISO** acted or directed others to act in accordance with requirement R4.

MR5 Evidence may include, but is not limited to dated computer printouts, dated operator logs, dated voice recordings, or other equivalent evidence that will be used in a situation where any **reliability coordinator** and the **ISO** disagree on the value of an **interconnection reliability operating limit** or its T_V, to confirm the **ISO** used the most conservative of the values under consideration, without delay.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Reliability Coordinator Data Specification and Collection
IRO-010-AB-1a

1. Purpose

To prevent instability, uncontrolled separation, or **cascading** that adversely impacts the reliability of the **Interconnection** by ensuring the **ISO** has the data it needs to monitor and assess the operation of its area.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must have a documented specification(s) for data and information to build and maintain models to support **real-time** monitoring, **operational planning analyses**, and **real-time assessments** of its area to prevent instability, uncontrolled separation, and **cascading**. The specification must include the following:

R1.1 list of required data and information needed by the **ISO** to support **real-time** monitoring, **operational planning analyses**, and **real-time assessments**;

R1.2 mutually agreeable format;

R1.3 timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its **operational planning analyses**); and

R1.4 process for data provision when automated **real-time** system operating data is unavailable.

R2 Intentionally left blank.

R3 The **ISO** must provide data and information, as specified upon, to each **reliability coordinator** with which it has a reliability relationship.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 The **ISO** may have evidence that could include, but is not limited to, a documented specification(s) for data and information that contains all specifications identified in requirement R1.

MR2 Intentionally left blank.

MR3 The **ISO** may have evidence to confirm that it provided data and information, as specified and mutually agreed upon in requirement R3. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated computer printouts, dated SCADA data, or other equivalent evidence.

Alberta Reliability Standard
Reliability Coordinator Data Specification and Collection
IRO-010-AB-1a

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Procedures, Processes or Plans to Support Coordination Between Reliability Coordinators
IRO-014-AB-1

1. Purpose

To ensure that the **ISO**'s operations are coordinated such that it will not have an **adverse reliability impact** on any **reliability coordinator area** and to preserve the reliability benefits of interconnected operations.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must have operating procedures, operating processes or operating plans in place for activities that require notification, exchange of information or coordination of actions with one or more **reliability coordinators** to support **Interconnection** reliability. These operating procedures, operating processes or operating plans must address anticipated events that affect **reliability coordinator areas** as well as those developed in coordination with **reliability coordinators**.

R1.1 These operating procedures, operating processes or operating plans must collectively address, as a minimum, the following:

R1.1.1 communications and notifications, including the conditions under which the **ISO** notifies a **reliability coordinator**; the process to follow in making those notifications; and the data and information to be exchanged with a **reliability coordinator**;

R1.1.2 energy and capacity shortages;

R1.1.3 planned or unplanned outage information;

R1.1.4 voltage control, including the coordination of reactive resources for voltage control;

R1.1.5 coordination of information exchange to support reliability assessments; and

R1.1.6 authority to act to prevent and mitigate instances of causing **adverse reliability impacts** to a **reliability coordinator area**.

R2 The **ISO**'s operating procedure, operating process or operating plan that requires one or more **reliability coordinators** to take action (e.g., make notifications, exchange information or coordinate actions) must be:

R2.1 agreed to by all the **reliability coordinators** required to take the indicated action(s); and

R2.2 distributed to all **reliability coordinators** that are required to take the indicated action(s).

R3 The **ISO**'s operating procedures, operating processes or operating plans developed to support an **ISO**-to-**reliability coordinator** operating procedure, operating process or operating plan must include:

R3.1 a reference to the associated **ISO**-to-**reliability coordinator** operating procedure, operating process or operating plan; and

R3.2 the agreed-upon actions from the associated **ISO**-to-**reliability coordinator** operating procedure, operating process or operating plan.

R4 The **ISO** must, for each of the operating procedures, operating processes and operating plans addressed in requirement R1 and requirement R3 of this **reliability standard**:

R4.1 include a version control number or date;

R4.2 include a distribution list; and

R4.3 conduct a review, at least once every three years, and updated if needed.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 The **ISO** may have available for real-time use, the latest approved version of operating procedures, operating processes or operating plans that require notifications, information exchange or the coordination of actions between **reliability coordinators** and the **ISO**.

MR1.1 These operating procedures, operating processes or operating plans may address:

MR1.1.1 communications and notifications, including the conditions under which the **ISO** notifies **reliability coordinators**; the process to follow in making those notifications; and the data and information to be exchanged between the **ISO** and **reliability coordinators**;

MR1.1.2 energy and capacity shortages;

MR1.1.3 planned or unplanned outage information;

MR1.1.4 voltage control, including the coordination of reactive resources for voltage control;

MR1.1.5 coordination of information exchange to support reliability assessments; and

MR1.1.6 authority to act to prevent and mitigate instances of causing **adverse reliability impacts** to a **reliability coordinator area**.

MR2 The **ISO** may have evidence that these operating procedures, operating processes or operating plans were:

MR2.1 agreed to by all the **reliability coordinators** required to take the indicated action(s); and

MR2.2 distributed to all **reliability coordinators** required to take the indicated action(s).

MR3 The **ISO**'s operating procedures, operating processes or operating plans developed to support an **ISO**-to-**reliability coordinator** operating procedure, operating process or operating plan may include:

MR3.1 a reference to the associated source document; and

MR3.2 the agreed-upon actions from the source document.

MR4 The **ISO**'s operating procedures, operating processes or operating plans that address **ISO**-to-**reliability coordinator** coordination may:

MR4.1 each include a version control number or date;

MR4.2 each include a distribution list; and

MR4.3 the **ISO** may have evidence that these operating procedures, operating processes or operating plans were reviewed within the last three years.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Notifications and Information Exchange Between Reliability Coordinators
IRO-015-AB-1

1. Purpose

To ensure that the **ISO**'s operations are coordinated such that it will not have an **adverse reliability impact** on adjacent **reliability coordinator areas** and to preserve the reliability benefits of interconnected operations.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must follow its operating procedures, operating processes or operating plans for making notifications and exchanging reliability-related information with adjacent **reliability coordinators**.

R1.1 The **ISO** must make notifications to adjacent **reliability coordinators** of conditions in its area that may have an **adverse reliability impact** on adjacent **reliability coordinator areas**.

R2 The **ISO** must participate in agreed upon conference calls and other communication forums with synchronously connected adjacent **reliability coordinators**.

R2.1 The frequency of these conference calls must be agreed upon by the **ISO** and all involved **reliability coordinators** and must be at least weekly.

R3 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 The **ISO** may have evidence that it has followed its operating procedures, operating processes or operating plans for notifying adjacent **reliability coordinators** of conditions in its area that may adversely impact adjacent **reliability coordinator areas** in accordance with requirement R1. Such evidence may include, but is not limited to, operator logs or other data sources.

MR2 The **ISO** may have evidence that it participated in agreed upon (at least weekly) conference calls and other communication forums with synchronously connected **reliability coordinators** in accordance with requirement R2. Such evidence may include, but is not limited to, operator logs or other data sources.

MR3 Intentionally left blank.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Coordination of Real-time Activities Between Reliability Coordinators
IRO-016-AB-1

1. Purpose

To ensure that the **ISO**'s operations are coordinated such that they will not have an **adverse reliability impact** on other **reliability coordinator areas** and to preserve the reliability benefits of interconnected operations.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 When the **ISO** identifies a potential, expected, or actual problem that requires the actions of one or more **reliability coordinators**, the **ISO** must contact the involved **reliability coordinator**(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.

R1.1 If the **ISO** and the involved **reliability coordinators** agree on the problem and the actions to take to prevent or mitigate the system condition, the **ISO** must implement the agreed-upon solution, and notify the involved **reliability coordinators** of the action(s) taken.

R1.2 If the **ISO** and the involved **reliability coordinators** cannot agree on the problem(s), the **ISO** must re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).

R1.2.1 If time permits, this re-evaluation must be done before taking corrective actions.

R1.2.2 If time does not permit, then the ISO must operate as though the problem(s) exist(s) until the conflicting system status is resolved.

R1.3 If the **ISO** and the involved **reliability coordinators** cannot agree on the solution, the more conservative solution must be implemented.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 For each event that requires coordination between the **ISO** and the involved **reliability coordinator**(s), the **ISO** may have evidence (operator logs or other data sources) of the actions taken for either the event or for the disagreement on the problem or for both.

Revision History

Effective Date	Description
2015-04-01	Initial release.

Alberta Reliability Standard
Steady-State and Dynamic Data for Transmission System Modeling and Simulation
MOD-010&012-AB-0

1 Purpose

The purpose of this **reliability standard** is to provide for the delivery of data and information necessary to establish consistent power flow and dynamic models to be used in the analysis of the reliability of the **Interconnection**.

2 Applicability

This **reliability standard** applies to:

(a) the **legal owner** of a **generating unit** that is:

(i) directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and

(ii) not part of an **aggregated generating facility**;

(b) the **legal owner** of an **aggregated generating facility** that is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(c) the **legal owner** of a **transmission facility**; and

(d) the **ISO**.

3 Requirements

R1 Each **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** and **legal owner** of **a transmission facility** must provide, within thirty (30) **days** of the **ISO**'s written request, equipment characteristics and system data that the **ISO** requires to meet requirements R2 and R3.

R2 Subject to requirement R3, the **ISO** must provide equipment characteristics and system data, including dynamics system modeling, simulation data and interchange schedules, to the **WECC** in compliance with the appropriate **Interconnection**-wide **WECC** steady-state and dynamics system modeling and simulation data requirements and reporting procedures.

R3 The **ISO** must provide the equipment characteristics and system data, including modeling data and information specified in requirement R2, according to the data bank compilation schedule the **WECC** publishes but if no such schedule has been published, then the **ISO** must provide such equipment characteristics and system data no later than:

(a) thirty (30) **days** from the date the **WECC** requests it if the **ISO** has received the requested information prior to the date that **WECC** requested it; or

(b) sixty (60) **days** from the date the **WECC** requests it if the **ISO** has not received the information prior to the date that **WECC** requested it.

4 Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of providing equipment characteristics and system data as required in requirement R1. Evidence may include data files, email or mail.

MR2 Evidence of providing equipment characteristics and system data as required in requirement R2. Evidence may include data files, email or mail.

MR3 Evidence of providing equipment characteristics and system data within the timelines specified in requirement R3. Evidence may include email or mail.

Revision History

Effective	Description
2014-01-01	Initial Release – The first day of the calendar quarter that follows three full calendar quarters after approval by the Commission

Alberta Reliability Standard
Demand and Energy Data
MOD-031-AB-2

1. Purpose

The purpose of this **reliability standard** is to identify the requirements for the **ISO** to provide to the **WECC**, demand, energy and related data to support **reliability** studies and assessments.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 Intentionally left blank.

R2 Intentionally left blank.

R3 The **ISO** must provide the data listed below, for the Alberta **balancing authority area**, to the **WECC** within 75 **days** of receiving a request for such data, unless the **WECC** and the **ISO** agree otherwise:

R3.1 any or all of the following actual data:

R3.1.1 integrated hourly **demands** in MWs for the prior calendar year;

R3.1.2 **monthly** and annual integrated peak hour **demands** in MWs for the prior calendar year;

R3.1.2.1 if the annual peak hour actual **demand** varies due to weather related conditions (e.g., temperature, humidity or wind speed), the **ISO** must also provide the weather normalized annual peak hour actual **demand** for the prior calendar year;

R3.1.3 **monthly** and annual net energy for load in GWhs for the prior calendar year; and

R3.1.4 **monthly** and annual peak hour controllable and dispatchable **demand** side management under the control or supervision of the **ISO** in MWs for the prior calendar year including, reporting for each hour: 1) the committed MWs (the amount under control or supervision); 2) the MWs issued in a **dispatch** (the amount, if any, activated for use by the system operator); and 3) the realized MWs (the amount of actual demand reduction);

R3.2 any or all of the following forecast data:

R3.2.1 **monthly** peak hour forecast total internal **demands** in MWs for the next 2 calendar years;

R3.2.2 **monthly** forecast net energy for load in GWhs for the next 2 calendar years;

R3.2.3 peak hour forecast total internal **demands** (summer and winter) in MWs for 10 calendar years into the future;

R3.2.4 annual forecast net energy for load in GWhs for 10 calendar years into the future; and

R3.2.5 total and available peak hour forecast of controllable and dispatchable **demand** side management (summer and winter), in MWs, under the control or supervision of the system operator for 10 calendar years into the future;

R3.3 any or all of the following summary explanations:

R3.3.1 the assumptions and methods used in the development of aggregated peak **demand** and net energy for load forecasts;

R3.3.2 the **demand** and energy effects of controllable and dispatchable **demand** side management under the control or supervision of the system operator;

R3.3.3 how **demand** side management is addressed in the forecasts of its peak **demand** and annual net energy for load;

R3.3.4 how the controllable and dispatchable **demand** side management forecast compares to actual controllable and dispatchable **demand** side management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted; and

R3.3.5 how the peak **demand** forecast compares to actual **demand** for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

R4 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Intentionally left blank.

MR2 Intentionally left blank.

MR3 Evidence of providing the data as required in requirement R3 exists. Evidence may include dated emails or dated transmittal letters, or other equivalent evidence.

MR4 Intentionally left blank.

Revision History

Date	Description
2018-08-01	Initial release.

Alberta Reliability Standard
Reliability Coordination - Staffing
PER-004-AB-2

1. Purpose

The **ISO** must have sufficient, competent staff to perform the functions of the **ISO**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must be staffed with adequately trained operating personnel, each possessing a valid NERC Reliability Operator certificate, 24 hours per **day**, seven **days** per week.

R2 The **ISO** must ensure that **ISO** operating personnel have adequate information regarding **system operating limits**, **interconnection reliability operating limits** and **intertie** facility limits available.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence may include, but is not limited to, NERC certificate / certification records, shift schedules or other equivalent evidence that will be used to confirm that the **ISO** is staffed with operating personnel possessing a valid NERC Reliability Operator certificate 24 hours per **day**, seven **days** per week.

MR2 Evidence may include but is not limited to, EMS screenshots, methodology documentation or other equivalent documentation that will be used to confirm that **ISO** operating personnel have adequate information regarding **system operating limits** and **interconnection reliability operating limits** and **intertie** facility limits.

Revision History

Effective Date	Description
2015-05-01	Initial release.

Alberta Reliability Standard
Operations Personnel Training
PER-005-AB-2

1. Purpose

The purpose of this **reliability standard** is to ensure that personnel performing or supporting **real time** operations on the **bulk electric system** are trained using a systematic approach.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**;

(b) the **operator** of a **transmission facility** that has personnel who can act independently to operate in **real time**, or to direct the **real time** operation of, those **transmission facilities** that are part of the **bulk electric system** from a **control centre**. This does not include field switching personnel.

This reliability standard does not apply to the **operator** of a **transmission facility** whose only **transmission facilities** are:

(i) radial **transmission facilities** connecting to:

  (a) load;

  (b) one or more **generating units**; and / or

  (c) one or more **aggregated generating facilities**; or

(ii) either part of an industrial complex or connected to an industrial complex and cannot interrupt power flow on the **interconnected electric system**, other than power flow on its own **transmission facilities**.

3. Requirements

R1 The **ISO** and each **operator** of a **transmission facility** must use a systematic approach to develop and implement a training program for its **real time** operating personnel, as follows:

R1.1 The **ISO** and each **operator** of a **transmission facility** must:

  (a) create a definition of a company-specific **real time** reliability-related task;

  (b) develop a documented methodology for determining company-specific **real time** reliability-related tasks; and

  (c) create a list of **bulk electric system** company-specific **real time** reliability-related tasks based on that methodology.

R1.1.1 The **ISO** and each **operator** of a **transmission facility** must review, and update if necessary, its list of **bulk electric system** company-specific **real time** reliability-related tasks identified in R1.1 each calendar year.

R1.2 The **ISO** and each **operator** of a **transmission facility** must design and develop training materials according to its training program, based on the **bulk electric system** company-specific **real time** reliability-related task list created in R1.1.

R1.3 The **ISO** and each **operator** of a **transmission facility** must deliver training to its **real time** operating personnel according to its training program.

R1.4 The **ISO** and each **operator** of a **transmission facility** must conduct an evaluation each calendar year of the training program established in requirement R1 to identify any needed changes to the training program, and must implement the changes identified.

R2 Intentionally left blank.

R3 The **ISO** and each **operator** of a **transmission facility** must verify, at least once, the capabilities of its **real time** operating personnel, identified in requirement R1, assigned to perform each of the **bulk electric system** company-specific **real time** reliability-related tasks identified under requirement R1.1.

R3.1 Within six (6) months of a modification or addition of a **bulk electric system** company-specific **real time** reliability-related task, the **ISO** and each **operator** of a **transmission facility** must verify the capabilities of each of its **real time** operating personnel identified in requirement R1 to perform the new or modified **bulk electric system** company-specific **real time** reliability-related tasks identified in requirement R1.1.

R4 The **ISO** must provide its **real time** operating personnel identified in requirement R1 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the **bulk electric system** if the **ISO**:

(1) has operational authority or control over **facilities** with established **interconnection reliability operating limits**, or

(2) has established **protection systems** or operating guides to mitigate **interconnection reliability operating limit** violations,

R4.1 The **ISO** must comply with requirement R4 within twelve (12) months of meeting either of the criteria identified in requirements R4(1) or R4(2).

R5 The **ISO** and each **operator** of a **transmission facility** must use a systematic approach to develop and implement training for its identified **operations support personnel** on how their job function(s) impact those **bulk electric system** company-specific **real time** reliability-related tasks that it has identified pursuant to requirement R1.1.

R5.1 The **ISO** and each **operator** of a **transmission facility** must conduct an evaluation each calendar year of the training established in requirement R5 to identify and implement changes to the training.

R6 Intentionally left blank.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for requirement R1.

MR1 Evidence of using a systematic approach to develop and implement a training program for its **real time** operating personnel as required in requirement R1 exists. Evidence may include, but is not limited to, training program descriptions, meeting minutes, design notes, or other equivalent evidence.

MR1.1 Evidence of having a definition, methodology and **bulk electric system** company-specific **real time** reliability-related task list and review history, as required in requirement R1.1 exists. Evidence may include, but is not limited to, a definition for **real time** reliability-related tasks, a documented methodology for determining company-specific **real time** reliability-related tasks, a list of **real time** reliability related tasks, a documented revision history or other equivalent evidence.

MR1.2 Evidence of designing and developing training materials as required in requirement R1.2 exists. Evidence may include, but is not limited to, course design documents and examples of training materials or other equivalent evidence.

MR1.3 Evidence of delivering **real time** operating personnel training, as required in requirement R 1.3 exists. Evidence may include, but is not limited to, training records showing the names of the attendees, the title of the training delivered, and the dates of delivery or other equivalent evidence.

MR1.4 Evidence of conducting an evaluation of the training program each calendar year and implementing the identified changes, as required in requirement R1.4 exists. Evidence may include, but is not limited to, instructor observations, trainee feedback, course evaluations, meeting minutes, training program document revision history, or other equivalent evidence.

MR2 Intentionally left blank.

MR3 Evidence of verifying, at least once, the capabilities of the **real time** operating personnel, as required in requirement R3 exists.

Evidence may include, but is not limited to, documented records to show that it verified the capability of each of its **real time** personnel on company-specific **real time** reliability-related tasks with the date of verification, employee name, supervisor signature and check sheets for each company-specific **real time** reliability-related task completed, the results of learning assessments, or other equivalent evidence.

MR3.1 Evidence of verifying the capabilities of **real time** operating personnel within six (6) months of a modification or addition of a **bulk electric system** company-specific **real time** reliability-related task, as required in requirement R3.1 exists. Evidence may include, but is not limited to, documented records to show that it verified the capability of each of its personnel on company-specific **real time** reliability-related tasks with the date of verification, employee name, supervisor signature and check sheets for each company-specific **real time** reliability-related task completed, the results of learning assessments, or other equivalent evidence.

MR4 Evidence of providing emergency operations training as required in requirement R4 exists. Evidence may include, but is not limited to, dated training records or other equivalent evidence.

MR4.1 Evidence of complying with requirement R4 as required in requirement R4.1 exists. Evidence may include, but is not limited to, dated training records or other equivalent evidence.

MR5 Evidence of using a systematic approach to develop and implement training for identified **operations support personnel** as required in requirement R5 exists. Evidence may include, but is not limited to, training records showing employee name, date of training and completion of training, or other equivalent evidence.

MR5.1 Evidence of conducting an evaluation each calendar year of the training established in requirement R5 and that any identified changes were implemented as required in requirement R5.1 exists. Evidence may include, but is not limited to, instructor observations, trainee feedback, course evaluations, meeting minutes, training program document revision history or other equivalent evidence.

MR6 Intentionally left blank.

Revision History

Date	Description
2018-04-01	Initial release.

Alberta Reliability Standard
Protection System Coordination
PRC-001-AB3-1.1(ii)

1. Purpose

The purpose of this **reliability standard** is to ensure **protection systems** are coordinated among operating entities.

2. Applicability

This **reliability standard** applies to:

(a) the **legal owner** of a **transmission facility** that is:

(i) part of the **bulk electric system**; or

(ii) not part of the **bulk electric system** and which the **ISO**:

(A) determines is necessary for the reliable operation of either the **interconnected electric system** or the City of Medicine Hat electric system; and

(B) publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;

(b) the **legal owner** of a **generating unit** that is:

(i) directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW;

(ii) within a power plant which:

(A) is not part of an **aggregated generating facility**;

(B) is directly connected to the **bulk electric system**; and

(C) has a combined **maximum authorized real power** rating greater 67.5 MW;

(iii) a **blackstart resource**; or

(iv) material to this **reliability standard** and to the reliability of the **bulk electric system**, regardless of its **maximum authorized real power** rating, as the **ISO** determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;

(c) the **legal owner** of an **aggregated generating facility** that is:

(i) directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW;

(ii) within a power plant or industrial complex which:

(A) is directly connected to the **bulk electric system**; and

(B) has a combined **maximum authorized real power** rating greater than 67.5 MW;

(iii) a **blackstart resource**; or

(iv) material to this **reliability standard** and to the reliability of the **bulk electric system**, regardless of its **maximum authorized real power** rating, as the **ISO** determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;

(d) the **operator** of a **transmission facility** that is:

(i) part of the **bulk electric system**; or

(ii) not part of the **bulk electric system** and which the **ISO**:

(A) determines is necessary for the reliable operation of either the **interconnected electric system** or the City of Medicine Hat electric system; and

(B) publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1;

(e) the **operator** of a **generating unit** that is:

(i) directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 18 MW;

(ii) within a power plant which:

(A) is not part of an **aggregated generating facility**;

(B) is directly connected to the **bulk electric system**; and

(C) has a combined **maximum authorized real power** rating greater than 67.5 MW;

(iii) a **blackstart resource**; or

(iv) material to this **reliability standard** and to the reliability of the **bulk electric system**, regardless of its **maximum authorized real power** rating, as the **ISO** determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1; and

(f) the **operator** of an **aggregated generating facility** that is:

(i) directly connected to the **bulk electric system** and has a **maximum authorized real power** rating greater than 67.5 MW;

(ii) within a power plant or industrial complex which:

(A) is directly connected to the bulk electric system; and

(B) has a combined maximum authorized real power rating greater than 67.5 MW;

(iii) a **blackstart resource**; or

(iv) material to this **reliability standard** and to the reliability of the **bulk electric system**, regardless of its **maximum authorized real power** rating, as the **ISO** determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1.

3. Requirements

R1 Each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** must, upon failure of any component of a **protection system** of a **generating unit** or an **aggregated generating facility** which it operates, take the actions listed in requirement R1.1 and R1.2.

R1.1 Notify the **operator** of a **transmission facility** to which the **generating unit** or **aggregated generating facility** is connected as soon as possible, but no longer than twenty-four (24) hours after becoming aware of such a failure, and provide the following information, regardless of whether or not the **generating unit** or **aggregated generating facility** remains on-line:

(a) identify the **protection system** that failed; and

(b) identify whether or not a **functionally equivalent protection system** remains in service.

R1.2 Correct the failure as soon as possible.

R2 Each **operator** of a **transmission facility**, **operator** of a **generating unit** and **operator** of an **aggregated generating facility** must take the actions listed in requirements R2.1 through R2.3 after becoming aware of the failure of any of the following **protection systems** or teleprotection communication channels under its authority:

(a) a **protection system**, other than a related teleprotection communication channel referred to in requirement R2(c) or R2(d), that protects a **transmission facility** operated at a nominal voltage greater than 200 kV, whether or not a **functionally equivalent protection system** remains in service;

(b) a **protection system**, other than a related teleprotection communication channel referred to in requirement R2(c) or R2(d), that protects a **transmission facility** that is part of the **bulk electric system** where a **functionally equivalent protection system** is not available;

(c) a teleprotection communication channel, that is part of a **protection system** for a **transmission facility** operated at a nominal voltage greater than 200 kV, where there is an equivalent backup teleprotection communication channel, and where the failure lasts for more than twenty-four (24) continuous hours; or

(d) a teleprotection communication channel, where there is no equivalent backup teleprotection communication channel, and where the failure lasts for more than ten (10) consecutive minutes.

R2.1 Provide notification to the **ISO**, and to each directly affected **operator** of a **transmission facility**, directly affected **operator** of a **generating unit**, directly affected **operator** of an **aggregated generating facility** and directly affected **interconnected transmission operator** as soon as possible, but no longer than twenty-four (24) hours after becoming aware of a failure identified in requirements R2(a), R2(b) and R2(d), and no longer than forty-eight (48) hours after becoming aware of a failure identified in requirement R2(c), regardless of whether or not the **transmission facility** is removed from service following the awareness of such failure, that includes the following information:

(a) the identification of the **protection system** or teleprotection communication channel(s) that failed;

(b) when the **protection system** or teleprotection communication channel(s) failed or when such failure was first discovered; and

(c) an estimate of the date when the **protection system** or teleprotection communication channel(s) will be returned to service.

R2.2 Where the protection system or teleprotection communication channel(s) are not returned to service by the estimated return to service date identified in requirement R2.1, provide a new estimate of the return to service date up to five (5) **days** after the previous estimated return to service date to the entities that received the notification in accordance with requirement R2.1.

R2.3 Correct the failure as soon as possible.

R3 Each **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must coordinate all new **protection systems** and all **protection system** changes with each affected interconnecting **legal owner** of a **transmission facility** and notify the **ISO** that such coordination has occurred.

R4 Each **legal owner** of a **transmission facility** must coordinate all new **protection systems** and all **protection system** changes with:

(a) each affected adjacent **legal owner** of a **transmission facility**;

(b) each affected **legal owner** of a **generating unit**;

(c) each affected **legal owner** of an **aggregated generating facility**;

(d) each affected **interconnected transmission operator**; and

(e) the **ISO**, as affected,

and must notify the **ISO** that such coordination has occurred.

R5 Each **operator** of a **generating unit**, **operator** of an **aggregated generating facility** and **operator** of a **transmission facility** must identify, notify and coordinate planned changes that may require changes in the **protection systems** of others as described in requirements R5.1 and R5.2.

R5.1 Each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** must identify planned changes to its generation, load, or operating conditions that may require changes to the **protection systems** of others, and must notify the **ISO** and coordinate with each affected **operator** of a **transmission facility** in advance of making such changes.

R5.2 Each **operator** of a **transmission facility** must identify planned changes to its transmission, load or operating conditions that may require changes to the **protection systems** of others, and must notify the **ISO** and coordinate with each affected:

(a) **operator** of a **transmission facility**;

(b) adjacent **interconnected transmission operator**;

(c) **operator** of a **generating unit**; and

(d) **operator** of an **aggregated generating facility**,

in advance of making such changes.

R6 Each **operator** of a **transmission facility** must monitor the status (on/off) of each **remedial action scheme** in its area, and must notify the **ISO** and each affected:

(a) **operator** of a **transmission facility**;

(b) adjacent **interconnected transmission operator**;

(c) **operator** of a **generating unit**; and

(d) **operator** of an **aggregated generating facility**,

of each change in status.

4. Measures

The following measures correspond to the requirements identified in section 3 of this reliability standard. For example, MR1 is the measure for requirement R1.

MR1 Evidence of notifying, providing information and correcting failures of any component of a **protection system** as required in requirement R1 exists. Evidence may include, but is not limited to:

MR1.1 voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence; and

MR1.2 work orders, setting change files, electronic records or other equivalent evidence.

MR2 Evidence of providing notification, providing an estimate and correcting failures of any of the **protection systems** or teleprotection communication channel(s) as required in requirement R2 exists. Evidence may include, but is not limited to:

MR2.1 voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence;

MR2.2 voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence; and

MR2.3 work orders, setting change files, electronic records or other equivalent evidence.

MR3 Evidence of coordinating **protection systems** and notifying the **ISO** as required in requirement R3 exists.

Evidence of coordinating **protection systems** may include, but is not limited to, a fault analysis study, letters of agreement on settings, notifications of changes or other equivalent evidence.

Evidence of notifying the **ISO** may include, but is not limited to, electronic notifications (emails), hard copy notifications, or other equivalent evidence.

MR4 Evidence of coordinating **protection systems** and notifying the **ISO** as required in requirement R4 exists.

Evidence of coordinating **protection systems** may include, but is not limited to, a fault analysis study, letters of agreement on settings, notifications of changes or other equivalent evidence.

Evidence of notifying the **ISO** may include, but is not limited to, electronic notifications (emails), hard copy notifications or other equivalent evidence.

MR5 Measures for this requirement are identified in the subsections below:

MR5.1 Evidence of identifying, notifying and coordinating planned changes that may require changes to the **protection systems** of others as required in requirement R5.1 exists.

Evidence may include, but is not limited to, voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence.

MR5.2 Evidence of identifying, notifying and coordinating planned changes that may require changes to the **protection systems** of others as required in requirement R5.2 exists.

Evidence may include, but is not limited to, voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence.

MR6 Evidence of monitoring the status of each **remedial action scheme** in its area and notifying entities of each change in status as required in requirement R6 exists.

Evidence of monitoring the status of each **remedial action scheme** may include, but is not limited to, SCADA data, wiring diagrams or other equivalent evidence.

Evidence of notifying entities may include, but is not limited to, SCADA data, voice recordings, operator logs, electronic notifications (emails) or other equivalent evidence.

Revision History

Date	Description
2017-10-01	Alberta specific revisions made to improve clarity.
2015-05-01	Revised for ISO assumption of RC functionality for the Alberta footprint
2013-01-02	Administrative update – “TFO” and “GFO” replaced with “legal owner of a transmission facility”, “operator of a transmission facility”, “legal owner of a generating unit”, “operator of a generating unit”, “legal owner of an aggregated generating facility”, and “operator of an aggregated generating facility”; applied standard at the bulk electric system level; added Appendix 1; and other minor cleanup items.
2011-01-13	R1
2010-01-22	New Issue

Appendix 1
Amending Process for List of Facilities

In order to amend any list referenced in subsections (a)(ii)(B), (b)(iv), (c)(iv), (d)(ii)(B), (e)(iv) and (f)(iv) of section 2, *Applicability*, the **ISO** must:

(a) upon determining that a **transmission facility**, **generating unit** or **aggregated generating facility** is to be added, notify the **legal owner** and **operator** in writing and determine an effective date, which must be no less than thirty (30) **days** after the date of notice, by which the **transmission facility**, **generating unit** or **aggregated generating facility** is to meet the applicable requirements;

(b) upon determining that a **transmission facility**, **generating unit** or **aggregated generating facility** is to be deleted, notify the **legal owner** and **operator** in writing and determine an effective date on which the **transmission facility**, **generating unit** or **aggregated generating facility** will no longer be required to meet the applicable requirements; and

(c) publish the amended list with effective dates on the AESO website.

PRC–004–AB1–1 Analysis and Mitigation of Transmission and Generation Protection System Misoperation

1. Purpose

The purpose of this *reliability standard* is to ensure all transmission and generation *protection system misoperations* affecting the *reliability* of the *BES* are analyzed and mitigated.

2. Applicability

This *reliability standard* applies to:

(a) the *legal owner* of a *transmission facility*;

(b) the *legal owner* of a *generating unit* that:

(i) is not part of an *aggregated generating facility*;

(ii) has a *maximum authorized real power* rating greater than four point five (4.5) MW;

(iii) is directly connected to the *transmission system* or to *transmission facilities* within the City of Medicine Hat; and

(iv) has *protection systems* that directly affect the *reliability* of the *bulk electric system* which such protection systems are those that measure voltage, current, or frequency from the *generating unit* to the *interconnected electric system*, but exclude the prime mover and associated control systems;

(c) the *legal owner* of an *aggregated generating facility* that:

(i) is directly connected to the *transmission system* or to *transmission facilities* within the City of Medicine Hat;

(ii) has a *maximum authorized real power* rating greater than four point five (4.5) MW; and

(iii) has *protection systems* that directly affect the *reliability* of the *bulk electric system*. These protection systems are those that measure voltage, current, or frequency from the *aggregated generating facility* to the *interconnected electric system*; and

(d) the *ISO*.

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the *Consolidated Authoritative Document Glossary*.

4. Requirements

R1 Each *legal owner of a transmission facility*, *legal owner* of a *generating unit* and *legal owner* of an *aggregated generating facility* must analyze its *protection system*

misoperations and develop and implement a *corrective action plan* to avoid future *misoperations* of a similar nature.

R2 Each *legal owner of a transmission facility, legal owner* of a *generating unit* and *legal owner* of an *aggregated generating facility* must provide to the *ISO* documentation of its *misoperations* analyses and *corrective action plans* upon request by the *ISO*.

R3 The *ISO* must provide to *WECC* documentation of the *misoperations* analyses and *corrective action plans* upon request by *WECC*.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Evidence exists and shows analysis was completed and *corrective action plans* were implemented as specified in requirement R1.

MR2 Evidence that analysis reports and *corrective action plans* were submitted as specified in requirement R2 (e.g. email confirmation).

MR3 Confirmation that documentation as specified in requirement R3 was received by *WECC* or evidence that requests for confirmation were made.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date:	Description
2013-01-02	Administrative update – "*TFO*" and "*GFO*" replaced with "*legal owner* of a *transmission facility*", "*legal owner* of a *generating unit*" and "*legal owner* of an *aggregated generating facility*"; and other minor clean up items.
2010-02-11	New Issue

Alberta Reliability Standard
Protection System and Remedial Action Scheme Misoperation
PRC-004-WECC-AB1-1

1. Purpose

The purpose of this **reliability standard** is to ensure all **misoperations** of transmission and generation **protection systems** and RASs on transmission paths are analyzed and mitigated.

2. Applicability

This **reliability standard** applies to:

(a) the **legal owner** of a **transmission facility** that is the **legal owner** of a **WECC** major transmission path **facility** or **RAS** listed in the tables titled "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC;**

(b) the **operator** of a **transmission facility** that operates a **WECC** major transmission path **facility** or **RAS** listed in the tables titled "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC;**

(c) the legal owner of a generating unit that owns components of RASs listed in the table titled "Major WECC Remedial Action Schemes (RAS)" as provided by the WECC;

(d) the **legal owner** of an **aggregated generating facility** that owns components of **RASs** listed in the table titled "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC;**

(e) the **operator** of a **generating unit** that operates **RASs** listed in the table titled "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC;**

(f) the **operator** of an **aggregated generating facility** that operates **RASs** listed in the table titled "Major WECC Remedial Action Schemes (RAS)" as provided by the **WECC**; and

(g) the **ISO**.

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the ***Consolidated Authoritative Document Glossary***.

4. Requirements

R1 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility**, **operator** of a **transmission facility**, **operator** of a **generating unit** and **operator** of an **aggregated generating facility** must ensure that its **system operator**s and protection personnel analyze all **protection system** and **RAS** operations as follows:

R1.1 Each **operator** of a **transmission facility**, **operator** of a **generating unit** and **operator** of an **aggregated generating facility** must review all tripping of transmission **system elements** and **RAS** operations to identify apparent **misoperations** within 24 hours.

R1.2 Protection personnel of the **legal owner** of a **transmission facility**, the **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility** must analyze all operations of **protection systems** and **RAS** within 20 business **days** of the

operation of either such system or **RAS** to determine whether a **misoperation** has occurred.

R2 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must perform the actions listed in requirements R2.1 to R2.4 inclusive for each **misoperation** of the **protection system** or **RAS**, subject to the following:

Requirements R2.1 to R2.4 inclusive do not apply to **protection system** and/or **RAS** operations that appear to have operated correctly at the time of occurrence. If the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** later finds through **system** protection personnel analysis that the **protection system** or **RAS** misoperated, the requirements of R2.1 to R2.4 inclusive become applicable at the time the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** identifies the **misoperation.**

Table 1 is provided as a simplified summary of the requirements in R2.1 to R2.4 inclusive.

2.1 If the **protection system** or **RAS** has a **security-based misoperation** and two or more **FEPS** or **FERAS** remain in service to ensure **BES reliability**, the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** must remove from service the **protection system** or **RAS** that misoperated, within 22 hours following the identification of the **misoperation**.

Repair or replacement of the failed **protection system** or **RAS** is at the discretion of the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility.**

R2.2 If the **protection system** or **RAS** has a **security-based misoperation** and only one **FEPS** or **FERAS** remains in service to ensure **BES reliability**, the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** responsible for the **protection system** or **RAS**, as the case may be, must perform the following:

R2.2.1 Remove from service, within 22 hours for repair or modification, the **protection system** or **RAS** that misoperated.

R2.2.2 Repair or replace any **protection system** or **RAS** that misoperated with a **FEPS** or **FERAS** within 20 business **days** of the date of removal.

R2.2.3 Remove the **system element** from service or disable the **RAS** if repair or replacement is not completed within 20 business **days.**

R2.3 If the **protection system** or **RAS** has a **security-based** or **dependability-based misoperation** and a **FEPS** or **FERAS** is not in service to ensure **BES reliability,** the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** responsible for the **protection system** or **RAS**, as the case may be, must repair and place back in service within 22 hours the **protection system** or **RAS** that misoperated.

If this cannot be done, the responsible legal owner of a transmission facility, legal owner of a generating unit or legal owner of an aggregated generating facility must perform the following:

R2.3.1 When a **FEPS** is not available, remove the associated **system element** from service.

R2.3.2 When **FERAS** is not available, meet one of the following requirements:

R2.3.2.1 If the responsible entity is a **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility,** it must advise the **ISO**, and the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** must adjust generation to a reliable operating level as directed by the **ISO.**

R2.3.2.2 If the responsible entity is a **legal owner** of a **transmission facility**, it must advise the **ISO**, and the **operator** of a **transmission facility** must operate the **facilities** within the adjusted **SOL** as determined and directed by the **ISO**.

R2.4 If the **protection system** or **RAS** has a **dependability-based misoperation**, but has one or more **FEPS** or **FERAS** that operated correctly, the associated **system element** or transmission path may remain in service without removing from service the **protection system** or **RAS** that failed, provided one of the following is performed

R2.4.1 The **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** must repair or replace any **protection system** or RAS that misoperated with **FEPS** and **FERAS** within 20 business **days** of the date of the **misoperation** identification, or

R2.4.2 The **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** must remove from service the associated **system element** or **RAS**.

R3 The **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** must submit a **misoperation** incident report to the **ISO** within six business **days** of identifying the **misoperation** for the following:

R3.1 Identification of a **misoperation** of a **protection system** and/or **RAS**

R3.2 Completion of repairs or the replacement of the protection system and/or **RAS** that misoperated.

R4 The **ISO** must submit **misoperation** incident reports to **WECC** within 10 business **days** of identifying the **misoperation**.

5. Processes and Procedures

No procedures have been defined for this **reliability standard**.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Measures for this requirement are identified in the subsections below.

MR1.1 Documentation exists that confirms a review was completed within the timelines as specified in requirement R1.1.

MR1.2 Documentation exists that confirms an analysis was completed and in the timelines as specified in requirement R1.2.

MR2 Measures for this requirement are identified in the subsections below.

MR2.1 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.1.

MR2.2 Measures for this requirement are identified in the subsections below**.**

MR2.2.1 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.2.1.

MR2.2.2 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.2.2.

MR2.2.3 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.2.3.

MR2.3 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.3**.**

MR2.3.1 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.3.1.

MR2.3.2 Measures for this requirement are identified in the subsections below.

MR2.3.2.1 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.3.2.1.

MR2.3.2.2 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.3.2.2.

MR2.4 Measures for this requirement are identified in the subsections below

MR2.4.1 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.4.1.

MR2.4.2 Evidence exists and shows that required actions were taken in the timelines as specified in requirement R2.4.2.

MR3 **Misoperation** incident report is submitted within timelines as specified in requirement R3.

MR3.1 **Misoperation** incident report contains content as specified in requirement R3.1.

MR3.2 **Misoperation** incident report contains content as specified in requirements R3.2.

MR4 Confirmation exists that incident reports as specified in requirement R4 were received within the timelines specified, or evidence that requests for confirmation were made for the incident reports provided as specified in requirement R4**.**

7. Appendices

Appendix 1 – Requirement R2: Table of Required Actions for Protection System or RAS Misoperation (see below)

8. Guidelines

No guidelines have been defined for this **reliability standard**.

Revision History

Date	Description
2016-08-30	Inclusion of the defined term **system element**.
2013-01-02	Administrative update – "**TFO** and **GFO**" replaced with "**legal owner** of a **transmission facility**" "**legal owner** of a **generating unit**" and "**legal owner** of an **aggregated generating facility**"; and other minor cleanup items.
2010-02-11	New Issue

Appendix 1 – Requirement R2: Table of Required Actions for Protection System or RAS Misoperation

PRC-004-WECC-1 Requirement R2 - Table of Required Actions for **Protection System** or **RAS Misoperation**					
Protective System/RAS Situation			Required Mitigating Actions		
Protection Basis:	Number of **FEPS** or **RAS** in place after **misoperation**	Misoperating **protection system** is:	**Protection System/RAS** Removal Requirement	**Protection System/RAS** Repair or Replacement Requirement	**System Element** Removal Requirement
Security	2 or more	PS	Remove within 22h.	At owners discretion.	
	1	PS	Remove within 22h.	Repair within 20 **days**.	Remove **system element** from service.
	0	PS	None.	Repair within 22 hours.	If not repaired in 22 hours then remove **system element** from service.
	2 or more	**RAS**	Remove within 22h.	At owners discretion.	
	1	**RAS**	Remove within 22h.	Repair within 20 **days**.	If not repaired in 20 days then disable **RAS** or remove **system element** from service.
	0	**RAS**	None.	Repair within 22 hours.	Either the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** must advise the **ISO**, and the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** must adjust generating operating levels to a reliable operating level as directed by the **ISO** or the **ISO** will adjust the **SOL** and the **operator** of a **transmission facility** will operate the **facilities** within established limits.

Dependability	1 or more that operated correctly	PS	Can leave in service.	Repair in 20 **days** or remove **system element** from service.	
	0	PS	None.	Repair within 22 hours.	If not repaired in 22 hours then remove **system element** from service.
	1 or more that operated correctly	PS	Can leave in service.	Repair in 20 **days** or remove **RAS** or **system element** from service.	
	0	**RAS**	None.	Repair within 22 hours.	Either the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** must advise the **ISO**, and the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** must adjust generating operating levels to a reliable operating level as directed by the **ISO** or the **ISO** will adjust the **SOL** and the **operator** of a **transmission facility** will operate the **facilities** within established limits.

PRC–009–AB–0 UFLS Performance Following an Undefrequency Event

1. Purpose

The purpose of this *reliability standard* is to ensure effectiveness of the *UFLS* program performance.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must analyze and document its *UFLS* program performance in accordance with *WECC's UFLS* program. The analysis must address the performance of *UFLS* equipment and program effectiveness following *system* events resulting in *system* frequency excursions below the initializing set points of the *UFLS* program. The analysis must include, without limitation the following:

- A description of the *system* event including initiating conditions.
- A review of the *UFLS* set points and tripping times.
- A simulation of the *system* event.
- A summary of the findings.

R2 The *ISO* must provide documentation of the analysis of the *UFLS* program performance to *WECC* on request and within the timeframe agreed to by the *ISO* and *WECC*.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Disturbance document(s) exist for each *UFLS* event. The disturbance document(s) contain analysis of the event.

MR2 Written confirmation from *WECC* that documentation was received.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date	Description
2009-10-03	New Issue

PRC–010–AB–0 Assessment of the Design and Effectiveness of Under Voltage Load Shedding Program

1. Purpose

The purpose of this *reliability standard* is to ensure the effectiveness of each *UVLS* program.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must conduct and document an assessment of the effectiveness of each *UVLS* program every five years. In the event the AESO determines that conditions affecting the *UVLS* operation have occurred, it may conduct and document an assessment within such five year period as it deems appropriate.

R2 The assessment of the effectiveness of each *UVLS* program must include without limitation, the following:

- Coordination of the *UVLS* programs with other protection and control systems in the *WECC* as appropriate.
- Simulations that demonstrate that the performance of each *UVLS* program is consistent with *reliability standards* TPL-001-AB-0, TPL-002-AB-0, TPL-003-AB-0 and TPL-004-AB-0.
- A review of the voltage set points and timing

R3 The *ISO* must provide documentation of its most recent assessment of *UVLS* programs to *WECC* on request and within the timeframe agreed to by the ISO and *WECC.*

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Documentation of the most recent assessment of the effectiveness of each *UVLS* program exists and was carried out within the last five years.

MR2 Documentation of the most recent assessment includes the elements of R2.

MR3 Written confirmation from *WECC* that the documentation requested by it pursuant to R3 has been received.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date	Description
2009-10-03	New Issue

Alberta Reliability Standard
Disturbance Monitoring Equipment Installation and Data Reporting
PRC-018-AB-1

1. Purpose

The purpose of this **reliability standard** is to ensure that **disturbance monitoring equipment** is installed and that **disturbance** data is reported in accordance with regional requirements to facilitate analyses of events.

2. Applicability

This **reliability standard** applies to:

(a) the **legal owner** of a **transmission facility** that owns **disturbance monitoring equipment** as identified in the list of *Disturbance Monitoring Equipment Locations* as required in requirement R1, as published by the **ISO** on the AESO website and as amended from time to time by the **ISO** on notice to **market participants**;

(b) the **legal owner** of a **generating unit** that owns **disturbance monitoring equipment** as identified in the list of *Disturbance Monitoring Equipment Locations* as required in requirement R1, as published by the **ISO** on the AESO website and as amended from time to time by the **ISO** on notice to **market participants**;

(c) the **legal owner** of an **aggregated generating facility** that owns **disturbance monitoring equipment** as identified in the list of *Disturbance Monitoring Equipment Locations* as required in requirement R1, as published by the **ISO** on the AESO website and as amended from time to time by the **ISO** on notice to **market participants**; and

(d) the **ISO**.

3. Requirements

R1 The **ISO** must maintain and publish a list of all **disturbance monitoring equipment** that this **reliability standard** applies to which includes all **disturbance monitoring equipment** the **WECC** requires to be installed in Alberta.

R2 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** that the **ISO** directs to install **disturbance monitoring equipment** must install such **disturbance monitoring equipment** with internal clocks synchronized to within two (2) milliseconds or less of the Universal Coordinated Time scale.

R3 The **ISO** must have recorded **disturbance** data available for retrieval for at least ten (10) **days**.

R4 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must install **disturbance monitoring equipment** as directed by the **ISO**.

R5 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must report, within thirty (30) **days** of the **ISO**'s request, the following information on the **disturbance monitoring equipment**:

R5.1 type of **disturbance monitoring equipment**;

R5.2 make and model of **disturbance monitoring equipment**;

R5.3 installation location;

R5.4 operational status;

R5.5 date last tested;

R5.6 monitored **system elements** which may include transmission circuit and bus section;

R5.7 monitored devices which may include circuit breaker, disconnect status and alarms; and

R5.8 monitored electrical quantities, which may include voltage and current.

R6 The **ISO** must provide the information received from the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** in requirement R5 to the **WECC** within forty-five (45) **days** of the **WECC**'s written request.

R7 If the **ISO** is unable to directly access **disturbance** data, then each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must provide all available **disturbance** data recorded by **disturbance monitoring equipment** to the **ISO** within forty-five (45) **days** of the **ISO**'s written request.

R8 The **ISO** must provide all available **disturbance** data recorded by the **disturbance monitoring equipment** of a **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** to the **WECC** within sixty (60) **days** of the **WECC**'s written request.

R9 The **ISO** must archive all data recorded by **disturbance monitoring equipment** for all **WECC** or **ISO** identified events for at least three (3) years.

R10 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** that the **ISO** directs to have **disturbance monitoring equipment** must develop, implement and maintain a maintenance and testing program for **disturbance monitoring equipment** that includes:

R10.1 maintenance and testing intervals and their basis; and

R10.2 a summary of maintenance and testing procedures.

4 Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of maintaining and publishing a list as required in requirement R1 exists. Evidence may include a list published on the AESO's website that identifies the effective date and revision history.

MR2 Evidence of having internal clocks in the installed **disturbance monitoring equipment** synchronized as required in requirement R2 exists. Evidence may include: the manufacturer's equipment specification, commissioning documents or GPS clock records that demonstrate each installed **disturbance monitoring equipment**'s internal clock is synchronized in accordance with R2.

MR3 Evidence of having recorded **disturbance** data available for retrieval as required in requirement R3 exists. Evidence may include **disturbance** records.

MR4 Evidence of installing **disturbance monitoring equipment** as required in requirement R4 exists. Evidence may include documentation of the installation of the **disturbance monitoring equipment**.

MR5 Evidence of reporting information as required in requirement R5 exists. Evidence may include email or mail to the appropriate **ISO** recipient that identifies information submitted.

MR6 Evidence of providing data as required in requirement R6 exists. Evidence may include email or mail to the appropriate **WECC** recipient that identifies data submitted.

MR7 Evidence of providing data as required in requirement R7 exists. Evidence may include email or mail to the appropriate **ISO** recipient that identifies data submitted.

MR8 Evidence of providing data as required in requirement R8 exists. Evidence may include email or mail to appropriate **WECC** recipient that identifies data submitted.

MR9 Evidence of archiving data as required in requirement R9 exists. Evidence may include dated archived data files.

MR10 Evidence of developing, implementing and maintaining a maintenance and testing program as required in requirement R10 exists. Evidence may include a documented maintenance and testing program, maintenance and testing records showing the test date, type of test, what was tested and test results.

MR10.1 Evidence of developing, implementing and maintaining a maintenance and testing program as required in requirement R10.1 exists. Evidence may include a documented maintenance and testing program that includes the provision as required in requirement R10.1.

MR10.2 Evidence of developing, implementing and maintaining a maintenance and testing program as required in requirement R10.2 exists. Evidence may include a documented maintenance and testing program that includes the provision as required in requirement R10.2.

5. Appendices

No appendices have been defined for this **reliability standard**.

Revision History

Effective	Description
2013-01-01	Initial Release
2016-08-30	Inclusion of the defined term **system element**.

PRC–021–AB1–1 Under Voltage Load Shedding Program Data

1. Purpose

The purpose of this *reliability standard* is to ensure data is provided to support the *WECC* database maintained for *UVLS* programs.

2. Applicability

This reliability standard applies to:

(a) the *legal owner* of a *transmission facility* that owns an *under voltage load shed* system;

(b) a *market participant* receiving service under Rate DTS of the *ISO tariff* that owns an *under voltage load shed* system; and

(c) the *ISO*.

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the *Consolidated Authoritative Document Glossary*.

4. Requirements

R1 The *ISO* must update its *UVLS* data annually to support the *WECC UVLS* database.

R2 The *ISO* must provide the following data to the *WECC* for each installed *UVLS* system in Alberta that is in the *WECC UVLS* database:

- Size and location of *load*, or percent of connected *load*, to be interrupted;
- Corresponding voltage set points and overall scheme clearing times;
- Time delay from initiation to trip signal;
- Breaker operating times; and
- Any other schemes that are part of or impact the *UVLS* programs, including without limitation related generation protection, islanding schemes, automatic *load* restoration schemes, *UFLS* and *RAS* (identified as *special protection systems* by *WECC*).

R3 Each *legal owner* of a *transmission facility* and *market participant* must, upon request by the *ISO*, provide *UVLS* data to the *ISO*. The *legal owner* of a *transmission facility* or *market participant* may meet this requirement R3 by providing *UVLS* data in accordance with *ISO* rules.

R4 The *ISO* must provide its *UVLS* data to the *WECC* within 30 calendar *days* of a written request to do so from *WECC*.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Evidence that the *UVLS* data update process was completed within 12 months of the previous update.

MR2 Written confirmation from *WECC* that *UVLS* data was received.

MR3 Written confirmation from the *ISO* that *UVLS* data was received.

MR4 Written confirmation from *WECC* that data was received within 30 calendar *days* of a request.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date	Description
2013-01-02	Administrative update – "*TFO*" and "*demand customers*" replaced with "*legal owner* of a *transmission facility*" and "*market participant* receiving service under Rate DTS of the *ISO tariff*"; and other minor cleanup items.
2009-09-19	New Issue

PRC–022–AB–1 Under Voltage Load Shedding Program Performance

1. Purpose

The purpose of this *reliability standard* is to ensure that *UVLS* programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the *AIES*.

2. Applicability

This *reliability standard* applies to:

- *ISO*

3. Definitions

Italicized terms used in this *reliability standard* have the meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.

4. Requirements

R1 The *ISO* must analyze and document *UVLS* operations and *misoperations* in accordance with *ISO* rules.

R2 The *ISO's* analysis of *UVLS* operations and *misoperations* must include without limitation, the following:

- A description of the *UVLS* event including initiating conditions.
- A review of the *UVLS* set points and tripping times.
- An analysis of the sequence of events.
- A summary of the findings.
- For any *misoperation*, a corrective action.

R3 The *ISO* must simulate the *UVLS* event, within the timeframe agreed to by the *ISO*, if *WECC* makes a written request for a simulation.

R4 The *ISO* must provide documentation of its analysis of a *UVLS* program performance to the *WECC* within 90 calendar *days* of a request from *WECC*.

5. Processes and Procedures

No procedures have been defined for this *reliability standard*.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this *reliability standard*. For example, MR1 is the measure for R1.

MR1 Event reports exist for *UVLS* events that require a report in accordance with *ISO* rules.

MR2 Documentation of the analysis includes the items listed in R2.

MR3 Results of the simulation exists.

MR4 Written confirmation from the *WECC* that documentation was received within 90 calendar *days*.

7. Appendices

No appendices have been defined for this *reliability standard*.

8. Guidelines

No guidelines have been defined for this *reliability standard*.

Revision History

Date	Description
2009-10-03	New Issue

Alberta Reliability Standard
Transmission Relay Loadability
PRC-023-AB-2

1. Purpose

The purpose of this **reliability standard** is to ensure the protective relay settings do not limit transmission loadability, do not interfere with an **operator**'s ability to take remedial action to protect the **reliability** of the system, and are set to reliably detect all fault conditions and protect the electrical network from these faults.

2. Applicability

This **reliability standard** applies to:

(a) a **legal owner** of a **transmission facility** with load-responsive phase **protection systems**, as described in Appendix 1 applied to any one (1) or more of the following facilities:

(i) transmission lines operated at two hundred (200) kV and above;

(ii) transmission lines operated below two hundred (200) kV which the **ISO** identifies as essential to the **reliability** of the **bulk electric system** as required in requirement R6.2;

(iii) transformers with low voltage terminals connected at two hundred (200) kV and above; or

(iv) transformers with low voltage terminals connected below two hundred (200) kV which the **ISO** identifies in accordance with requirement R6.2;

(b) a **legal owner** of a **generating unit,** that also owns the associated switch yard, with load-responsive phase **protection systems**, as described in Appendix 1 applied to any one (1) or more of the following facilities:

(i) transmission lines operated at two hundred (200) kV and above;

(ii) transmission lines operated below two hundred (200) kV which the **ISO** identifies as essential to the **reliability** of the **bulk electric system** as required in requirement R6.2;

(iii) transformers with low voltage terminals connected at two hundred (200) kV and above; or

(iv) transformers with low voltage terminals connected below two hundred (200) kV which the **ISO** identifies in accordance with requirement R6.2;

(c) a **legal owner** of an **aggregated generating facility,** that also owns the associated switch yard, with load-responsive phase **protection systems**, as described in Appendix 1 applied to any one (1) or more of the following facilities:

(i) transmission lines operated at two hundred (200) kV and above;

(ii) transmission lines operated below two hundred (200) kV which the **ISO** identifies as essential to the **reliability** of the **bulk electric system** as required in requirement R6.2;

(iii) transformers with low voltage terminals connected at two hundred (200) kV and above; or

(iv) transformers with low voltage terminals connected below two hundred (200) kV which the **ISO** identifies in accordance with requirement R6.2; and

(d) the **ISO**.

3. Requirements

R1 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must use one of the criteria set out in requirements R1.1 through R1.14, inclusive, for each specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the **bulk electric system** for all fault conditions and evaluate the phase protective relay's loadability at zero point eight five (0.85) per unit voltage and a **power factor** angle of thirty (30) degrees.

R1.1 Set transmission line relays so they do not operate at or below one hundred and fifty (150 %) percent of the highest seasonal facility rating of a circuit for the available defined loading duration nearest to four (4) hours, expressed in amperes;

R1.2 Set transmission line relays so they do not operate at or below one hundred and fifteen (115 %) percent of the highest seasonal 15-minute facility rating of a circuit, expressed in amperes;

R1.3 Set transmission line relays so they do not operate at or below one hundred and fifteen (115%) percent of the maximum theoretical power transfer capability, using a ninety (90) degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance of the circuit, expressed in amperes, using one of the following to perform the power transfer calculation:

R1.3.1 an infinite source, i.e. zero source impedance, with a one point zero zero (1.00) per unit bus voltage at each end of the transmission line; or

R1.3.2 an impedance at each end of the transmission line, which reflects the actual system source impedance with a one point zero five (1.05) per unit voltage behind each source impedance;

R1.4 Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the transmission line, determined as the greater of:

(a) one hundred and fifteen (115 %) percent of the highest emergency rating of the series capacitor, or

(b) one hundred and fifteen (115%) percent of the maximum power transfer capability of the circuit, expressed in amperes, calculated in accordance with requirement R1.3, using the full transmission line inductive reactance;

R1.5 Set transmission line relays on weak source systems so they do not operate at or below one hundred and seventy (170%) percent of the maximum end-of-line three-phase fault magnitude, expressed in amperes;

R1.6 Set transmission line relays applied on transmission lines connected to a **generating unit** or **aggregated generating facility** remote to load so they do not operate at or below two hundred and thirty (230%) percent of the total nameplate capability of all the **generating unit**s at the facility;

R1.7 Set transmission line relays applied at the load center terminal, remote from a **generating unit** or **aggregated generating facility**, so they do not operate at or below one hundred and fifteen (115%) percent of the maximum current flow from the load to the generation source under any system configuration;

R1.8 Set transmission line relays applied on the system-end of transmission lines that serve load remote to the system so they do not operate at or below one hundred and fifteen (115%) percent of

the maximum current flow from the system to the load under any system configuration;

R1.9 Set transmission line relays applied on the load-end of transmission lines that serve load remote to the system so they do not operate at or below one hundred and fifteen (115%) of the maximum current flow from the load to the system under any system configuration;

R1.10 Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

(a) one hundred and fifty (150%) percent of the applicable maximum transformer nameplate rating, expressed in amperes, including the forced cooled ratings corresponding to all installed supplemental cooling equipment; or

(b) one hundred and fifteen (115%) percent of the highest established emergency transformer rating;

R1.11 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability;

R1.12 For transformer overload protection relays that do not comply with requirement R1.10:

(a) set the relays to allow the transformer to be operated at an overload level of at least one hundred and fifty (150%) percent of the maximum applicable nameplate rating, or one hundred and fifteen (115%) percent of the highest emergency transformer rating, whichever is greater;

(b) the protection relay must allow overload in subsection 1.12(a) for at least fifteen (15) minutes to allow the **ISO** to take controlled action to relieve the overload;

(c) install supervision for the relays using either a top oil or simulated winding hot spot temperature element; and

(d) the relay setting should be no less than one hundred (100°C) degrees Celsius for the top oil or one hundred and forty (140°C) degrees Celsius for the winding hot spot temperature;

R1.13 When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of one hundred and twenty five (125%) percent of the apparent impedance, at the impedance angle of the transmission line, subject to the following constraints:

R1.13.1 Set the maximum torque angle to ninety (90) degrees or the highest setting supported by the manufacturer;

R1.13.2 Evaluate the relay loadability in amperes at the relay trip point at zero point eight five (0.85) per unit voltage and a **power factor** angle of thirty (30) degrees; and

R1.13.3 Include a relay setting component of eighty seven (87%) percent of the current calculated in requirement R1.13.2 in the facility rating determination for the circuit; and

R1.14 Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below one hundred and fifteen (115%) percent of such limitations.

R2 Each **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay

loadability per requirement R1.

R3 Any **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** that uses a circuit capability with the practical limitations described in requirements R1.6, R1.7, R1.8, R1.9, R1.13, or R1.14 must use the calculated circuit capability as the facility rating of the circuit and must obtain the agreement of the **ISO** to use the calculated circuit capability.

R4 Any **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** that uses requirement R1.2 as the basis for verifying transmission line relay loadability must provide the **ISO** with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than fifteen (15) months between reports.

R5 Any **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** or **legal owner** of an **aggregated generating facility** that uses requirement R1.13 as the basis for verifying transmission line relay loadability must provide the **ISO** with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than fifteen (15) months between reports.

R6 The **ISO** must conduct an assessment at least once each calendar year, with no more than fifteen (15) months between assessments, by applying the criteria in Appendix 2 to identify the circuits in its Planning Coordinator area for which the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must comply with requirements R1 through R5. The **ISO** must:

R6.1 Maintain a list of circuits per the application of Appendix 2, including an effective date that is no earlier than twenty-four (24) months from identification of the circuits; and

R6.2 Provide the list of circuits to the **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** within its Planning Coordinator area within thirty (30) days of the establishment of the initial list and within thirty (30) days of any changes to that list.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of using one of the criteria set out in requirements R1.1 through R1.14 as required in requirement R1 exists. Evidence may include:

(a) spreadsheets or summaries of calculations to show that each of its transmission relays is set in accordance with one of the criteria set out in requirements R1.1 through R1.14; and

(b) coordination curves or summaries of calculations that show that relays set per criterion set out in requirement R1.11 do not expose the transformer to fault levels and durations beyond those indicated in the **reliability standard**.

MR2 Evidence of setting its out-of-step blocking elements as required in requirement R2 exists. Evidence may include spreadsheets or summaries of calculations.

MR3 Evidence of using, and obtaining the agreement to use, the calculated circuit capability as required in requirement R3 exists. Evidence may include:

(a) facility rating spreadsheets or facility rating database to show that the calculated circuit

capability was used as the facility rating of the circuit; and

(b) dated correspondence to show that the **ISO** agreed to the calculated circuit capability.

MR4 Evidence of providing the **ISO** with an updated list of circuits as required in requirement R4 exists. Evidence may include email or mail to the appropriate **ISO** recipient with the updated list which may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list.

MR5 Evidence of providing the **ISO** with an updated list of circuits as required in requirement R5 exists. Evidence may include email or mail to the appropriate **ISO** recipient with the updated list which may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list.

MR6 Evidence of conducting an assessment as required in requirement R6 exists. Evidence may include power flow results, calculation summaries or study reports that the **ISO** used the criteria established within Appendix 2 to identify the circuits in its Planning Coordinator area.

MR6.1 Evidence of maintaining the list of circuits as required in requirement R6.1 exists. Evidence may include a documented list of circuits with the effective date and the revision history captured.

MR6.2 Evidence of providing the list of circuits as required in requirement R6.2 exists. Evidence may include email or mail to the applicable entities.

5. Appendices

Appendix 1 – *Associated Switch Yard with Load-Responsive Phase Protection Systems*

Appendix 2 – *Criteria for Identifying Circuits and Establishing a List*

Revision History

Effective	Description
April 1, 2015	for requirements R1, R2, R3, R4 and R5 for: (a) transmission lines operated at two hundred (200) kV and above; and (b) transformers with low voltage terminals connected at two hundred (200) kV and above.
April 1, 2014	for requirement R6
April 1, 2016	for requirements R1, R2, R3, R4 and R5 for: (a) transmission lines operated below two hundred (200) kV which the **ISO** identifies as essential to the **reliability** of the **bulk electric system**; and (b) transformers with low voltage terminals connected below two hundred (200) kV the **ISO** identifies as essential to the **reliability** of the **bulk electric system**.

Appendix 1 – Associated Switch Yard with Load-Responsive Phase Protection Systems

1. This **reliability standard** includes any protective functions which could trip with or without time delay, on load current, including:

   (a) phase distance;

   (b) out-of-step tripping;

   (c) switch-on-to-fault;

   (d) overcurrent relays;

   (e) communications aided **protection schemes** including:

      (i) permissive overreach transfer trip;

      (ii) permissive under-reach transfer trip;

      (iii) directional comparison blocking; and

      (iv) directional comparison unblocking; and

   (f) phase overcurrent supervisory elements (i.e. phase fault detectors) associated with current-based, communication-assisted schemes (i.e. pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following **protection systems** are excluded from the requirements of this **reliability standard**:

   (a) relay elements that are only enabled when other relays or associated systems fail, including:

      (i) overcurrent elements that are only enabled during loss of potential conditions; and

      (ii) elements that are only enabled during a loss of communications except as noted in subsection 1(f) above;

   (b) **protection systems** intended for the detection of ground fault conditions;

   (c) **protection systems** intended for protection during stable power swings;

   (d) generator protection relays that are susceptible to load;

   (e) relay elements used only for **remedial action scheme** purposes;

   (f) **protection systems** that are designed only to respond in time periods which allow fifteen (15) minutes or greater to respond to overload conditions;

   (g) thermal emulation relays which are used in conjunction with dynamic facility ratings; and

   (h) relay elements associated with direct current lines.

Appendix 2 – Criteria for Identifying Circuits and Establishing a List

The **ISO** must evaluate the following circuits**:**

(a) transmission lines operated at one hundred (100) kV to two hundred (200) kV and transformers with low voltage terminals connected at one hundred (100) kV to two hundred (200) kV; and

(b) transmission lines operated below one hundred (100) kV and transformers with low voltage terminals connected below one hundred (100) kV that are essential to the **reliability** of the **bulk electric system**.

Criteria

If any of the following criteria apply to a circuit, the **ISO** must identify the circuit as required in requirement R6.

1 A major transfer path within the Western **Interconnection** as defined by the Regional Entity.

2 The circuit is a monitored facility of an **interconnection reliability operating limit**, where the **interconnection reliability operating limit** was determined in the planning horizon pursuant to **reliability standard** *FAC-010-AB-2.1, System Operation Limits Methodology for the Planning Horizon*.

3 The circuit is identified through the following sequence of power flow analyses:

(a) simulate double **contingency** combinations selected by engineering judgment, without manual system adjustments in between the two (2) **contingencies** (reflects a situation where a system operator may not have time between the two (2) **contingencies** to make appropriate system adjustments), performed by the **ISO** for the one-to-five-year planning horizon;

(b) for circuits operated between one hundred (100) kV and two hundred (200) kV, evaluate the post-**contingency** loading, in consultation with the **legal owner**, against a threshold based on the facility rating assigned for that circuit and used in the power flow case by the **ISO**;

(c) when more than one (1) facility rating for that circuit is available in the power flow case, the **ISO** must base the threshold for selection on the facility rating for the loading duration nearest four (4) hours;

(d) the threshold for selection of the circuit will vary based on the loading duration assumed in the development of the facility rating:

(i) if the facility rating is based on a loading duration of up to and including four (4) hours, the circuit must comply with the standard if the loading exceeds one hundred and fifteen percent (115%) of the facility rating;

(ii) if the facility rating is based on a loading duration greater than four (4) and up to and including eight (8) hours, the circuit must comply with the standard if the loading exceeds one hundred and twenty percent (120%) of the facility rating; or

(iii) if the facility rating is based on a loading duration of greater than eight (8) hours, the circuit must comply with the standard if the loading exceeds one hundred and thirty percent (130%) of the facility rating; and

(e) radially operated circuits serving only load are excluded.

4 The **ISO** must select the circuit based on technical studies or assessments, other than those specified in criteria 1 through 3, in consultation with the **legal owner**.

5 The **ISO** and the **legal owner** must mutually agree upon the circuit for inclusion.

Alberta Reliability Standard
Operational Reliability Information
TOP-005-AB3-1

1. Purpose

The purpose of this **reliability standard** is to require the **ISO** to provide operating data to entities responsible for reliable power system operation so that those entities have the operating data needed to monitor system conditions within their areas.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 Intentionally left blank.

R2 Upon request, the **ISO** must provide to other **balancing authorities** and **transmission operators** external to Alberta with immediate responsibility for operational **reliability**, the operating data that is necessary to allow these **balancing authorities** and **transmission operators** external to Alberta to perform operational **reliability** assessments and to coordinate reliable operations. The **ISO** must provide the types of operating data as listed in Appendix 1 of this **reliability standard**, unless otherwise agreed to by these **balancing authorities** and **transmission operators**.

R3 Upon request, the **ISO** must provide to each **operator** of a **transmission facility** with immediate responsibility for operational **reliability**, the operating data that is necessary to allow such **operator** of a **transmission facility** to perform operational **reliability** assessments and to coordinate reliable operations. The **ISO** must provide the types of operating data as listed in Appendix 1 of this **reliability standard**, unless otherwise agreed to by the **operator** of a **transmission facility** and with immediate responsibility for operational **reliability**.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Intentionally left blank.

MR2 A confirmation letter from the **ISO** confirming that the **ISO** has provided the data as requested by the **balancing authorities** or **transmission operators**. The letter is dated and signed by an authorized representative of the **balancing authorities** and **transmission operators** external to Alberta.

MR3 A confirmation letter from the **ISO** confirming that the **ISO** has provided the data as requested by the **operator** of a **transmission facility**. The letter is dated and signed by an authorized representative of the **operator** of a **transmission facility**.

5. Appendices

Appendix 1 - TOP-005-AB3-1 Electric System Reliability Data

Revision History

Date	Description
2015-10-01	Revised for ISO assumption of RC functionality for the Alberta footprint.
2013-04-01	Remove requirements R2 and R5 applicable to non-**ISO** Alberta entities.
2013-01-02	Administrative update – "*TFO*" replaced with "**operator** of a **transmission facility**"; clarified "*pool participant*"; specified "**operator** of a *generating unit*"; and specified "**operator** of an *aggregated generating facility*".
2009-05-26	New Issue

Appendix 1 - TOP-005-AB3-1 Electric System Reliability Data

Appendix 1 lists the types of data that the **ISO** is expected to provide to:

(i) other **balancing authorities** and **transmission operators** external to Alberta; and

(ii) each **operator** of a **transmission facility**;

with immediate responsibility for operational **reliability**.

1. The following operating data must be updated at least every ten (10) minutes.

1.1 Transmission data. Transmission data for all **interconnections** plus all other facilities considered key, from a **reliability** standpoint:

1.1.1 Status

1.1.2 MW or ampere loadings

1.1.3 MVA capability

1.1.4 Transformer tap and phase angle settings

1.1.5 Key voltages

1.2 Generator data:

1.2.1 Status

1.2.2 MW and MVAr capability

1.2.3 MW and MVAr net output

1.2.4 Status of automatic voltage control facilities

1.3. Operating reserves:

1.3.1 MW reserve available within ten minutes

1.4. **Balancing authority** demand:

1.4.1 Instantaneous

1.5. **Interchange**:

1.5.1 Instantaneous actual **interchange** with each **balancing authority**

1.5.2 Current **interchange schedules** with each **balancing authority** by individual **interchange transaction**, including **interchange** identifiers, and reserve responsibilities

1.5.3 **Interchange schedules** for the next twenty-four (24) hours

1.6. **Area control error** and frequency:

1.6.1 Instantaneous **area control error**

1.6.2 Clock hour **area control error**

1.6.3 System frequency at one (1) or more locations in the **balancing authority**

2. The following information must be updated as soon as the information becomes available.

2.1. **Interconnection reliability operating limits** and **system operating limits** in effect

2.2. Forecast of operating reserves at peak, and time of peak for current **day** and next **day**

2.3. Forecast **peak demand** for current **day** and next **day**

2.4. Forecast changes in equipment status

2.5. New facilities in place

2.6. New or degraded **remedial action schemes**

2.7. Emergency operating procedures in effect

2.8. Severe weather, fire, or earthquake

2.9. Multi-site sabotage

Alberta Reliability Standard
System Performance Under Normal Conditions
TPL-001-AB-0

1. Purpose

The purpose of this **reliability standard** is to ensure that a reliable transmission system is planned that meets specified performance requirements, with sufficient lead time. The transmission system must continue to be modified or upgraded as required to meet present and future system specified performance requirements as identified by periodically performed system simulations and associated planning assessments.

2. Applicability

This **reliability standard** applies to:

(a) **ISO**

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the *Consolidated Authoritative Document Glossary* and Part 1 of the ISO Rules.

4. Requirements

R1 The **ISO** must demonstrate through a planning assessment that a transmission system is planned such that, with all **transmission facilities** in service and with pre-**contingency** operating procedures in effect, the transmission system can be operated to accommodate forecasted customer **demands**, supply and forecasted **firm** (non- recallable reserved) transmission services at all **demand** levels over the range of forecast system **demands**, under the conditions defined in Category A of Appendix 1.

The **ISO** planning assessment must:

R1.1 Be carried out annually.

R1.2 Be conducted for years one through five and years six through ten planning horizons.

R1.3 Be supported by a study and/or system simulation testing, conducted within the last five years, that addresses each of the requirements in requirement R1.3.1 to R1.3.9, showing system performance for the conditions defined in Category A of Appendix 1.

R1.3.1 Cover critical system conditions and study years as determined necessary by the **ISO**.

R1.3.2 Be conducted annually unless the **ISO** determines that changes to system conditions do not warrant such analyses.

R1.3.3 Be conducted beyond the five year planning horizon only as needed to address identified marginal conditions that may have longer lead time solutions.

R1.3.4 Have pre-**contingency** operating procedures established and in place.

R1.3.5 Have all projected firm transfers modeled, if any.

R1.3.6 Be performed for selected **demand** levels over the range of forecast system **demands** as considered necessary by the **ISO**.

R1.3.7 Demonstrate that system performance meets the conditions defined in Category A of Appendix 1.

R1.3.8 Include existing and planned **facilities** as considered necessary by the **ISO**.

R1.3.9 Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.

R1.4 Address any planned upgrades needed to meet the performance requirements for the conditions defined in Category A of Appendix 1.

R2 When system simulations indicate an inability of the systems to respond as set out in R1.3.7 in this **reliability standard**, the **ISO** must:

R2.1 Develop corrective plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1 Including a schedule for implementation.

R2.1.2 Including a discussion of expected required in-service dates of **facilities**.

R2.1.3 Consider lead times necessary to implement corrective plans**.**

R2.2 Review in subsequent annual assessments, where sufficient lead time exists, the continuing need for identified system **facilities**. Detailed implementation plans are not needed.

R3 The **ISO** must provide the planning assessment to **WECC** on an annual basis.

5. Processes and Procedures

No procedures have been defined for this **reliability standard**.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 The planning assessment will be valid and meet requirement in R1 through the following measures:

(a) The scope of the planning assessment identifies where area studies have been conducted in the past year. It also identifies area studies that have been conducted in previous years and are still valid. Where area studies have not been conducted, a plan and schedule to conduct one is included in the planning assessment.

(b) The planning assessment includes time horizons as specified in R1.2.

(c) The planning assessment has been prepared within the last year.

(d) A certification that the planning assessment complies with each of the R1 technical requirements is provided and states that the planning assessment meets all requirements, identifies requirements not met, and states reasons where the requirement was not met.

(e) A summary list of supporting area studies and needs identification documents is provided. The summary list includes the title and date of the study. The area studies and needs identification documents are provided if requested.

MR2 The area studies and needs identification documents contain recommendations and projects for corrective plans where an inability of the systems to respond to requirements specified in R1 has been identified. The area studies and needs identification documents are provided on request. The

area studies and needs identification documents contain the technical components as specified in R2 and its subsections.

MR3 A written or email confirmation from **WECC** that it has received the planning assessment from the **ISO**. The confirmation includes the date of when the planning assessment was received and source identification information.

7. Appendices

Appendix 1 - Transmission System Standards – Normal and Emergency Conditions (see below)

8. Guidelines

No guidelines have been defined for this **reliability standard**.

Revision History

Date	Description
2010-09-24	New Issue
2016-08-30	Inclusion of the defined term **system element**.

Appendix 1 - Transmission System Standards – Normal and Emergency Conditions

Category	**Contingencies**	System Limits or Impacts		
	Initiating Event(s) and Contingency **System Element(s)**	System Stable and Both Thermal and Voltage Limits Within Applicable **Rating**[a]	Loss of **Demand** or Curtailed Firm Transmission Service Transfers	**Cascading**
A No **contingencies**	All **facilities** in service	Yes	No	No
B Event resulting in the loss of a single **system element**	Single Line Ground (SLG) or 3-Phase (3Ø) fault, with **normal clearing**:	Yes	No[b]	No
	1. Generator	Yes	No[b]	No
	2. Transmission circuit	Yes	No[b]	No
	3. Transformer	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) **system elements**	SLG fault, with **normal clearing**[e]:			
	1. Bus section	Yes	Planned/ Controlled[c]	No
	2. Breaker (failure or internal fault)	Yes	Planned/ Controlled[c]	No
	SLG or 3Ø fault, with **normal clearing**[e], manual system adjustments, followed by another SLG or 3Ø fault, with **normal clearing**[e]			
	3. Category B (B1, B2, B3, or B4) **contingency**, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) **contingency**	Yes	Planned/ Controlled[c]	No
	Bipolar block, with **normal clearing**[e]:			
	4. Bipolar (dc) line fault (non 3Ø), with **normal clearing**[e]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[t]	Yes	Planned/ Controlled[c]	No
	SLG fault, with delayed clearing[e] (stuck breaker or **protection system** failure)			

	6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission circuit	Yes	Planned/ Controlled[c]	No
	9. Bus section	Yes	Planned/ Controlled[c]	No
D [d] Extreme event resulting in two or more (multiple) **system elements** removed or **cascading** out of service	3Ø fault, with delayed clearing[e] (stuck breaker or **protection system** failure): 1. Generator 2. Transmission circuit 3. Transformer 4. Bus section 3Ø fault, with **normal clearing**[e]: 5. Breaker (failure or internal fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of -way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large **load** or major **load** center 12. Failure of a fully redundant **special protection system** (or **remedial action scheme**) to operate when required 13. Operation, partial operation, or **misoperation** of a fully redundant **special protection system** (or **remedial action scheme**) in response to an event or abnormal system 14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization		Evaluate for risks and consequences • May involve substantial loss of customer demand and generation in a widespread area or areas • Portions or all of the **interconnected** systems may or may not achieve a new, stable operating point • Evaluation of these events may require joint studies with neighboring systems	

a) Applicable **rating** refers to the applicable normal and emergency **facility** thermal and voltage **rating** as applied by the **facility** owner or system voltage limit as determined and consistently applied by the ISO. Applicable **ratings** may include emergency **ratings** applicable for short durations as required to permit operating steps necessary to maintain system control. All **ratings** must be established by the applicable entity consistent with applicable **ISO** rules addressing **facility ratings**.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted **system element** or by the affected area, may occur in certain areas without impacting the overall **reliability** of the **interconnected** transmission systems. To prepare for the next **contingency**, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (**load** shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) transmission service electric power transfers may be necessary to maintain the overall **reliability** of the **interconnected** transmission systems.

d) A number of extreme **contingencies** that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible **facility outages** under each listed **contingency** of Category D will be evaluated.

e) **Normal clearing** is when the **protection system** operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed **protection systems**. Delayed clearing of a fault is due to failure of any **protection system** component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (i.e., station entrance, river crossings) in accordance with exemption criteria.

Alberta Reliability Standard
System Performance Following Loss of a Single BES Element
TPL-002-AB1-0

1. Purpose

The purpose of this **reliability standard** is to ensure that a reliable transmission system is planned that meets specified performance requirements with sufficient lead time. The transmission system must continue to be modified or upgraded as required to meet present and future system specified performance requirements as identified by periodically performed system simulations and associated planning assessments.

2. Applicability

This **reliability standard** applies to:

(a) **ISO**

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the *Consolidated Authoritative Document Glossary* and Part 1 of the ISO Rules.

4. Requirements

R1 The **ISO** must demonstrate for **transmission facilities** rated 69 kV and above, through a planning assessment, that a transmission system is planned such that the transmission system can be operated to accommodate forecasted customer **demands** and forecasted firm (non-recallable reserved) transmission services, at all **demand** levels over the range of forecast system **demands**, under the **contingency** conditions as defined in Category B of Appendix 1.

The **ISO** planning assessments must:

R1.1 Be carried out annually.

R1.2 Be conducted for near term (year one through five) and longer term (year six through ten) planning horizons.

R1.3 Be supported by a study and/or system simulation testing, conducted within the last five years that addresses each of the requirements in requirement R1.3.1 to R1.3.12, showing system performance for the conditions defined in Category B of Appendix 1.

R1.3.1 Be performed and evaluated only for those Category B **contingencies** that the **ISO** has determined would produce the more severe system results or impacts. The rationale for the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe system results must be included in the study.

R1.3.2 Cover critical system conditions and study years as determined necessary by the **ISO**.

R1.3.3 Be conducted annually unless the **ISO** determines that changes to system conditions do not warrant such analyses.

R1.3.4 Be conducted beyond the five year horizon only as needed to address identified marginal conditions that may have longer lead time solutions.

R1.3.5 Have all projected firm transfers modeled, if any.

R1.3.6 Be performed and evaluated for selected **demand** levels over the range of forecast system **demands** as considered necessary by the *ISO*.

R1.3.7 Demonstrate that system performance meets the conditions defined in Category B of Appendix 1.

R1.3.8 Include existing and planned **facilities** as considered necessary by the **ISO**.

R1.3.9 Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10 Include the effects of existing and planned **protection systems**, including any backup or redundant systems.

R1.3.11 Include the effects of existing and planned control devices.

R1.3.12 Include the planned **outage** and maintenance of any bulk electric equipment (including **protection systems** or their components) at those **demand** levels for which planned (including maintenance) **outages** are performed. For stations supplied by two lines, if one line is out for maintenance, then those stations are considered to be supplied by a radial line.

R1.4 Address any planned upgrades needed to meet the performance requirements for the conditions defined in Category B of Appendix 1.

R1.5 Consider all **contingencies** applicable to Category B of Appendix 1.

R2 When system simulations indicate an inability of the systems to respond as set out in R1.3.7 of this **reliability standard** the **ISO** must:

R2.1 Provide corrective plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1 Including a schedule for implementation.

R2.1.2 Including a discussion of expected required in-service dates of **facilities**.

R2.1.3 Consider lead times necessary to implement corrective plans**.**

R2.2 Review, in subsequent annual assessments, where sufficient lead time exists, the continuing need for identified system **facilities**. Detailed implementation plans are not needed**.**

R3 The **ISO** must provide the planning assessment to **WECC** on an annual basis.

5. Processes and Procedures

No procedures have been defined for this **reliability standard**.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 The planning assessment will be valid and meet requirements in R1 through the following measures:

(a) The scope of the planning assessment identifies where area studies have been conducted in the past year. It also identifies area studies that have been conducted in previous years and

are still valid. Where area studies have not been conducted, a plan and schedule to conduct one is included in the planning assessment.

(b) The planning assessment includes time horizons as specified in R1.2.

(c) The planning assessment has been prepared within the last year.

(d) A certification that the planning assessment complies with each of the R1 technical requirements is provided and states that the planning assessment meets all requirements, identifies requirements not met, and states reasons where the requirement was not met.

(e) A summary list of supporting area studies and needs identification documents is provided. The summary list includes the title and date of the study. The area studies and needs identification documents are provided if requested.

MR2 The area studies and needs identification documents contain recommendations and projects for the corrective plans where an inability of the systems to respond to requirements specified in R1 has been identified. The area studies and needs identification documents must be provided on request.

MR3 A written or email confirmation from **WECC** that it has received the planning assessment from the **ISO**. The confirmation includes the date of when the planning assessment was received and source identification information.

7. Appendices

Appendix 1 - Transmission System Standards – Normal and Emergency Conditions (see below)

8. Guidelines

No guidelines have been defined for this **reliability standard**.

Revision History

Date	Description
2017-10-30	Initial release.

Appendix 1 - Transmission System Standards – Normal and Emergency Conditions

Category	**Contingencies** Initiating Event(s) and Contingency **System Element(s)**	System Limits or Impacts System Stable and Both Thermal and Voltage Limits Within Applicable **Rating**[a]	Loss of **Demand** or Curtailed Firm Transmission Service Transfers	**Cascading**
A No **contingencies**	All **facilities** in service	Yes	No	No
B Event resulting in the loss of a single **system element**	Single Line Ground (SLG) or 3-Phase (3Ø) fault, with **normal clearing**:	Yes	No[b]	No
	1. Generator	Yes	No[b]	No
	2. Transmission circuit	Yes	No[b]	No
	3. Transformer	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) **system elements**	SLG fault, with **normal clearing**[e]:			
	1. Bus section	Yes	Planned/ Controlled[c]	No
	2. Breaker (failure or internal fault)	Yes	Planned/ Controlled[c]	No
	SLG or 3Ø fault, with **normal clearing**[e], manual system adjustments, followed by another SLG or 3Ø fault, with **normal clearing**[e]			
	3. Category B (B1, B2, B3, or B4) **contingency**, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) **contingency**	Yes	Planned/ Controlled[c]	No
	Bipolar block, with **normal clearing**[e]:			
	4. Bipolar (dc) line fault (non 3Ø), with **normal clearing**[e]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[t]	Yes	Planned/ Controlled[c]	No
	SLG fault, with delayed clearing[e] (stuck breaker or **protection system** failure)			

	6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission circuit	Yes	Planned/ Controlled[c]	No
	9. Bus section	Yes	Planned/ Controlled[c]	No
D [d] Extreme event resulting in two or more (multiple) **system elements** removed or **cascading** out of service	3Ø fault, with delayed clearing[e] (stuck breaker or **protection system** failure): 1. Generator 2. Transmission circuit 3. Transformer 4. Bus section 3Ø fault, with **normal clearing**[e]: 5. Breaker (failure or internal fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of -way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large **load** or major **load** center 12. Failure of a fully redundant **special protection system** (or **remedial action scheme**) to operate when required 13. Operation, partial operation, or **misoperation** of a fully redundant **special protection system** (or **remedial action scheme**) in response to an event or abnormal system 14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization		Evaluate for risks and consequences • May involve substantial loss of customer demand and generation in a widespread area or areas • Portions or all of the **interconnected** systems may or may not achieve a new, stable operating point • Evaluation of these events may require joint studies with neighboring systems	

a) Applicable **rating** refers to the applicable normal and emergency **facility** thermal and voltage **rating** as applied by the **facility** owner or system voltage limit as determined and consistently applied by the ISO. Applicable *ratings* may include emergency **ratings** applicable for short durations as required to permit operating steps necessary to maintain system control. All **ratings** must be established by the applicable entity consistent with applicable *ISO* rules addressing **facility ratings**.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted **system element** or by the affected area, may occur in certain areas without impacting the overall **reliability** of the **interconnected** transmission systems. To prepare for the next **contingency**, system

adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (**load** shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) transmission service electric power transfers may be necessary to maintain the overall **reliability** of the **interconnected** transmission systems.

d) A number of extreme **contingencies** that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible **facility outages** under each listed **contingency** of Category D will be evaluated.

e) **Normal clearing** is when the **protection system** operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed ***protection* systems**. Delayed clearing of a fault is due to failure of any **protection system** component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (i.e., station entrance, river crossings) in accordance with exemption criteria.

Alberta Reliability Standard
System Performance Following Loss of Two or more BES Elements
TPL-003-AB-0

1. Purpose

The purpose of this **reliability standard** is to ensure that a reliable transmission system is planned that meets specified performance requirements, with sufficient lead time. The transmission system must continue to be modified or upgraded as required to meet present and future system specified performance requirements as identified by periodically performed system simulations and associated planning assessments.

2. Applicability

This **reliability standard** applies to:

(a) **ISO**

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the *Consolidated Authoritative Document Glossary* and Part 1 of the ISO Rules.

4. Requirements

R1 The **ISO** must demonstrate for **transmission facilities** rated 100 kV and above, through a planning assessment that the **AIES** is planned such that the **AIES** can be operatedto accommodate forecasted customer **demands**, supply and forecasted firm (non- recallable reserved) transmission services, at all demand **levels** over the range of forecast system **demands**, under the **contingency** conditions as defined in Category C of Appendix 1. The controlled interruption of **demand** to **demand customers**, the planned removal of generating units, or the curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this **reliability standard**.

The **ISO** planning assessments must:

R1.1 Be carried out annually.

R1.2 Be conducted for near term (year one through five) and longer term (year six through ten) planning horizons.

R1.3 Be supported by a study and/or system simulation testing, conducted within the last five years that addresses each of the requirements in requirement R1.3.1 to R1.3.1, showing system performance for the conditions defined in Category C of Appendix 1.

R1.3.1 Be performed and evaluated only for those Category C **contingencies** that the **ISO** determines would produce the more severe system results or impacts. The rationale for the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe system results must be included in the study.

R1.3.2 Cover critical system conditions and study years as determined necessary by the *ISO*.

R1.3.3 Be conducted annually unless the ISO determines that changes to system conditions do not warrant such analyses.

R1.3.4 Be conducted beyond the five year planning horizon only as needed to address identified marginal conditions that may have longer lead- time solutions.

R1.3.5 Have all projected firm transfers modeled, if any.

R1.3.6 Be performed and evaluated for selected **demand** levels over the range of forecast system **demands** as considered necessary by the **ISO**.

R1.3.7 Demonstrate that system performance meets the conditions defined in Category C of Appendix 1.

R1.3.8 Include existing and planned **facilities** as considered necessary by the **ISO**.

R1.3.9 Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7 Demonstrate that system performance meets the conditions defined in Category C of Appendix 1.

R1.3.8 Include existing and planned **facilities** as considered necessary by the **ISO**.

R1.3.9 Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10 Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11 Include the effects of existing and planned control devices.

R1.3.12 Include the planned **outage** and maintenance of any bulk electric equipment (including **protection systems** or their components) at those **demand** levels for which planned (including maintenance) **outages** are performed. This requirement applies only to **BES facilities** greater than 200 kV or other **facilities** as specified by the **ISO**.

R1.4 Address any planned upgrades needed to meet the performance requirements for the conditions defined in Category C of Appendix 1.

R1.5 Consider all **contingencies** applicable to Category C of Appendix 1.

R2 When system simulations indicate an inability of the systems to respond as set out inR1.3.7 of this reliability standard, the **ISO** must:

R2.1 Provide corrective plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1 Including a schedule for implementation.

R2.1.2 Including a discussion of expected required in-service dates of **facilities**.

R2.1.3 Consider lead times necessary to implement plans.

R2.2 Review in subsequent annual assessments where sufficient lead time exists, the continuing need for identified system **facilities**. Detailed implementation plans are not needed.

R3 The **ISO** must provide the planning assessment to **WECC** on an annual basis.

5. Processes and Procedures

No procedures have been defined for this **reliability standard**.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 The planning assessment will be valid and meet requirements in R1 through the following measures:

(a) The scope of the planning assessment identifies where area studies have been conducted in the past year. It also identifies area studies that have been conducted in previous years and are still valid. Where area studies have not been conducted, a plan and schedule to conduct one is included in the planning assessment.

(b) The planning assessment includes time horizons as specified in R1.2.

(c) The planning assessment has been prepared within the last year.

(d) A certification that the planning assessment complies with each of the R1 technical requirements is provided and states that the planning assessment meets all requirements, identifies requirements not met, and states reasons where the requirement was not met.

(e) A summary list of supporting area studies and needs identification documents is provided. The summary list includes the title and date of the study. The area studies and needs identification documents are provided if requested.

MR2 The area studies and needs identification documents contain recommendations and projects that correct the situations where an inability of the systems to respond to requirements specified in R1 has been identified. The area studies and needs identification documents are provided on request.

The area studies and needs identification documents contain the technical components as specified in R2 and its subsections.

MR3 A written or email confirmation from **WECC** that it has received the planning assessment from the **ISO**. The confirmation includes the date of when the planning assessment was received and source identification information.

7. Appendices

Appendix 1 - Transmission System Standards – Normal and Emergency Conditions (see below)

8. Guidelines

No guidelines have been defined for this **reliability standard**.

Revision History

Date	Description
2010-09-24	Initial release.
2016-08-30	Inclusion of the defined term **system element**.

Appendix 1 - Transmission System Standards – Normal and Emergency Conditions

Category	**Contingencies**	System Limits or Impacts		
	Initiating Event(s) and Contingency **System Element(s)**	System Stable and Both Thermal and Voltage Limits Within Applicable **Rating**[a]	Loss of **Demand** or Curtailed Firm Transmission Service Transfers	**Cascading**
A No **contingencies**	All **facilities** in service	Yes	No	No
B Event resulting in the loss of a single **system element**	Single Line Ground (SLG) or 3-Phase (3Ø) fault, with **normal clearing**:	Yes	No[b]	No
	1. Generator	Yes	No[b]	No
	2. Transmission circuit	Yes	No[b]	No
	3. Transformer	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) **system elements**	SLG fault, with **normal clearing**[e]:			
	1. Bus section	Yes	Planned/ Controlled[c]	No
	2. Breaker (failure or internal fault)	Yes	Planned/ Controlled[c]	No
	SLG or 3Ø fault, with **normal clearing**[e], manual system adjustments, followed by another SLG or 3Ø fault, with **normal clearing**[e]			
	3. Category B (B1, B2, B3, or B4) **contingency**, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) **contingency**	Yes	Planned/ Controlled[c]	No
	Bipolar block, with **normal clearing**[e]:			
	4. Bipolar (dc) line fault (non 3Ø), with **normal clearing**[e]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[t]	Yes	Planned/ Controlled[c]	No
	SLG fault, with delayed clearing[e] (stuck breaker or **protection system** failure)			

	6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission circuit	Yes	Planned/ Controlled[c]	No
	9. Bus section	Yes	Planned/ Controlled[c]	No
D [d] Extreme event resulting in two or more (multiple) **system elements** removed or **cascading** out of service	3Ø fault, with delayed clearing[e] (stuck breaker or **protection system** failure): 1. Generator 2. Transmission circuit 3. Transformer 4. Bus section 3Ø fault, with **normal clearing**[e]: 5. Breaker (failure or internal fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of -way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large **load** or major **load** center 12. Failure of a fully redundant **special protection system** (or **remedial action scheme**) to operate when required 13. Operation, partial operation, or **misoperation** of a fully redundant **special protection system** (or **remedial action scheme**) in response to an event or abnormal system 14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization		Evaluate for risks and consequences • May involve substantial loss of customer demand and generation in a widespread area or areas • Portions or all of the **interconnected** systems may or may not achieve a new, stable operating point • Evaluation of these events may require joint studies with neighboring systems	

a) Applicable **rating** refers to the applicable normal and emergency **facility** thermal and voltage **rating** as applied by the **facility** owner or system voltage limit as determined and consistently applied by the ISO. Applicable **ratings** may include emergency **ratings** applicable for short durations as required to permit operating steps necessary to maintain system control. All **ratings** must be established by the applicable entity consistent with applicable **ISO** rules addressing **facility ratings**.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted **system element** or by the affected area, may occur in certain areas without impacting the overall **reliability** of the **interconnected** transmission systems. To prepare for the next **contingency**, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (**load** shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) transmission service electric power transfers may be necessary to maintain the overall **reliability** of the **interconnected** transmission systems.

d) A number of extreme **contingencies** that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible **facility outages** under each listed **contingency** of Category D will be evaluated.

e) **Normal clearing** is when the **protection system** operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed **protection systems**. Delayed clearing of a fault is due to failure of any **protection system** component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (i.e., station entrance, river crossings) in accordance with exemption criteria.

Alberta Reliability Standard
System Performance Following Extreme BES Events
TPL-004-AB-0

1. Purpose

The purpose of this **reliability standard** is to ensure that a reliable transmission system is planned that meets specified performance requirements with sufficient lead time. The transmission system must continue to be modified or upgraded as required to meet present and future system specified performance requirements as identified by periodically performed system simulations and associated planning assessments.

2. Applicability

This **reliability standard** applies to:

(a) **ISO**

3. Definitions

Bold terms used in this **reliability standard** have the meanings as set out in the *Consolidated Authoritative Document Glossary* and Part 1 of the ISO Rules.

4. Requirements

R1 The ISO must demonstrate for transmission facilities rated 100 kV and above, through a planning assessment that a transmission system is planned such that it has been evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Appendix 1.

The **ISO** planning assessments must:

R1.1 Be carried out annually.

R1.2 Be conducted for near term (year one through five).

R1.3 Be supported by a study and/or system simulation that addresses each of the following categories, showing system performance following Category D **contingencies** of Appendix 1.

R1.3.1 Be performed and evaluated only for those Category D **contingencies that** *ISO* determines would produce the more severe system results or impacts. The rationale for the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe system results must be included in the study.

R1.3.2 Cover critical system conditions and study years as considered necessary by the **ISO**.

R1.3.3 Be conducted annually unless the **ISO** determines that changes to system conditions do not warrant such analyses.

R1.3.4 Have all projected firm transfers modeled, if any.

R1.3.5 Include existing and planned **facilities** as considered necessary by the **ISO**.

R1.3.6 Include **reactive power** resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7 Include the effects of existing and planned **protection systems**, including any backup or redundant systems.

R1.3.8 Include the effects of existing and planned control devices.

R1.3.9 Include the planned **outage** and maintenance of any bulk electric equipment (including **protection systems** or their components) at those **demand** levels for which planned (including maintenance) **outages** are performed. This requirement applies only to **BES facilities** greater than 200 kV or other **facilities** as specified by the **ISO**.

R1.4 Consider all **contingencies** applicable to Category D of Appendix 1.

R2 The **ISO** must provide the planning assessment to **WECC** on an annual basis.

5. Processes and Procedures

No procedures have been defined for this **reliability standard**.

6. Measures

The following measures correspond to the requirements identified in Section 4 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 The planning assessment will be valid and meet requirement in R1 and associated sub-sections through the following measures:

(a) The scope of the planning assessment identifies where area studies have been conducted in the past year. It also identifies area studies that have been conducted in previous years and are still valid. Where area studies have not been conducted, a plan and schedule to conduct one is included in the planning assessment.

(b) The planning assessment includes time horizons as specified in R1.2.

(c) The planning assessment has been prepared within the last year.

(d) A certification that the planning assessment complies with each of the R1 technical requirements is provided and states that the planning assessment meets all requirements, identifies requirements not met, and states reasons where the requirement was not met.

(e) A summary list of supporting area studies and needs identification documents is provided. The summary list includes the title and date of the study. The area studies and needs identification documents are provided if requested.

MR2 A written or email confirmation from **WECC** that it has received the planning assessment from the **ISO**. The confirmation includes the date of when the planning assessment was received and source identification information.

7. Appendices

Appendix 1 - Transmission System Standards – Normal and Emergency Conditions (see below)

8. Guidelines

No guidelines have been defined for this **reliability standard**.

Revision History

Date	Description
2010-09-24	Initial release.
2016-08-30	Inclusion of the defined term **system element**.

Appendix 1 - Transmission System Standards – Normal and Emergency Conditions

Category	**Contingencies**	System Limits or Impacts		
	Initiating Event(s) and Contingency **System Element(s)**	System Stable and Both Thermal and Voltage Limits Within Applicable **Rating**[a]	Loss of **Demand** or Curtailed Firm Transmission Service Transfers	**Cascading**
A No **contingencies**	All **facilities** in service	Yes	No	No
B Event resulting in the loss of a single **system element**	Single Line Ground (SLG) or 3-Phase (3Ø) fault, with **normal clearing**:	Yes	No[b]	No
	1. Generator	Yes	No[b]	No
	2. Transmission circuit	Yes	No[b]	No
	3. Transformer	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) **system elements**	SLG fault, with **normal clearing**[e]:			
	1. Bus section	Yes	Planned/ Controlled[c]	No
	2. Breaker (failure or internal fault)	Yes	Planned/ Controlled[c]	No
	SLG or 3Ø fault, with **normal clearing**[e], manual system adjustments, followed by another SLG or 3Ø fault, with **normal clearing**[e]			
	3. Category B (B1, B2, B3, or B4) **contingency**, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) **contingency**	Yes	Planned/ Controlled[c]	No
	Bipolar block, with **normal clearing**[e]:			
	4. Bipolar (dc) line fault (non 3Ø), with **normal clearing**[e]:	Yes	Planned/ Controlled[c]	No
	5. Any two circuits of a multiple circuit towerline[t]	Yes	Planned/ Controlled[c]	No
	SLG fault, with delayed clearing[e] (stuck breaker or **protection system** failure)			

	6. Generator	Yes	Planned/ Controlled[c]	No
	7. Transformer	Yes	Planned/ Controlled[c]	No
	8. Transmission circuit	Yes	Planned/ Controlled[c]	No
	9. Bus section	Yes	Planned/ Controlled[c]	No
D [d] Extreme event resulting in two or more (multiple) **system elements** removed or **cascading** out of service	3Ø fault, with delayed clearing[e] (stuck breaker or **protection system** failure): 1. Generator 2. Transmission circuit 3. Transformer 4. Bus section 3Ø fault, with **normal clearing**[e]: 5. Breaker (failure or internal fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of -way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large **load** or major **load** center 12. Failure of a fully redundant **special protection system** (or **remedial action scheme**) to operate when required 13. Operation, partial operation, or **misoperation** of a fully redundant **special protection system** (or **remedial action scheme**) in response to an event or abnormal system 14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization		Evaluate for risks and consequences • May involve substantial loss of customer demand and generation in a widespread area or areas • Portions or all of the **interconnected** systems may or may not achieve a new, stable operating point • Evaluation of these events may require joint studies with neighboring systems	

a) Applicable **rating** refers to the applicable normal and emergency **facility** thermal and voltage **rating** as applied by the **facility** owner or system voltage limit as determined and consistently applied by the ISO. Applicable **ratings** may include emergency **ratings** applicable for short durations as required to permit operating steps necessary to maintain system control. All **ratings** must be established by the applicable entity consistent with applicable **ISO** rules addressing **facility ratings**.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted **system element** or by the affected area, may occur in certain areas without impacting the overall **reliability** of the **interconnected** transmission systems. To prepare for the next **contingency**, system

adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (**load** shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) transmission service electric power transfers may be necessary to maintain the overall **reliability** of the **interconnected** transmission systems.

d) A number of extreme **contingencies** that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible **facility outages** under each listed **contingency** of Category D will be evaluated.

e) **Normal clearing** is when the **protection system** operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed **protection systems**. Delayed clearing of a fault is due to failure of any **protection system** component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (i.e., station entrance, river crossings) in accordance with exemption criteria.

Alberta Reliability Standard
Voltage and Reactive Control
VAR-001-AB-4

1. Purpose

To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in **real-time** to protect equipment and the reliable operation of the **Interconnection**.

2. Applicability

This **reliability standard** applies to:

(a) the **ISO**.

3. Requirements

R1 The **ISO** must specify a system voltage range with an associated tolerance band, as part of its plan to operate within **system operating limits** and **interconnection reliability operating limits**.

R1.1 The **ISO** must provide a copy of the system voltage range with an associated tolerance band to an **interconnected transmission operator** within thirty (30) **days** of a request.

R2 The **ISO** must operate with sufficient **reactive power** resources available within Alberta to protect the voltage levels of the **transmission system** under normal and **contingency** conditions.

R3 The **ISO** must be able to regulate transmission voltage and **reactive power** flow by issuing **directives** or instructions to operate the devices necessary to do so.

R4 The **ISO** must specify the criteria that will exempt a **generating unit** or an **aggregated generating facility** from:

a) following a voltage or **reactive power** instruction or **directive**;

b) having its **automatic voltage regulator** or **voltage regulating system** in service or being in voltage control mode; or

c) making any associated notifications.

R4.1 If the **ISO** determines that a **generating unit** or an **aggregated generating facility** has satisfied the exemption criteria, the **ISO** must notify the associated **operator** of a **generating unit** or **operator** of an **aggregated generating facility**.

R5 The **ISO**, when issuing **directives** or instructions for voltage level or **reactive power**, to the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility**, must specify the following:

a) the voltage level at the **point of connection** between the **transmission system** and a **generating unit** or an **aggregated generating facility**, including those in a power plant or an industrial complex; or

b) the **reactive power** to be achieved by the **generating unit**, **aggregated generating facility**,

power plant or industrial complex.

R6 The **ISO** must, after a review with the **legal owner** of a **generating unit** or the **legal owner** of an **aggregated generating facility** regarding necessary off-load tap changes for the step-up transformer that connects to the **transmission system**, provide documentation to the **legal owner** of a **generating unit** or the **legal owner** of an **aggregated generating facility** specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard.** For example, MR1 is the measure for R1.

MR1. Evidence of specifying a system voltage range with an associated tolerance band as required in requirement R1 exists.

MR1.1 Evidence of providing a copy of the system voltage range with an associated tolerance band as required in requirement R1.1 exists. Evidence may include, but is not limited to, emails, website postings, or any other equivalent evidence.

MR2 Evidence of operating with sufficient **reactive power** resources as required in requirement R2 exists. Evidence may include, but is not limited to, data files or any other equivalent evidence.

MR3 Evidence of being able to regulate transmission voltage and **reactive power** flow as required in requirement R3 exists. Evidence may include, but is not limited to, relevant **ISO** authoritative documents.

MR4 Evidence of specifying the criteria that will exempt a **generating unit** or an **aggregated generating facility** as specified in requirement R4 exists.

MR4.1 Evidence of notifying the associated **operator** of a **generating uni**t or **operator** of an **aggregated generating facility** if the **ISO** determines that the exemption criteria were satisfied. Evidence may include, but is not limited to, emails, data files or other equivalent evidence.

MR5 Evidence of issuing **directives** or instructions to the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** as required in requirement R5 exists. Evidence may include, but is not limited to, voice recordings or other equivalent evidence.

MR6 Evidence of providing documentation as required in requirement R6 exists. Evidence may include, but is not limited to, dated study results or email to appropriate recipients that identifies contents submitted or other equivalent evidence.

5. Appendices

Appendix 1 - *Exemptions*

Revision History

Date	Description
2012-10-01	Initial release
2016-04-01	Revised to align with NERC version 4.

Appendix 1 - Exemptions

1. Exemption Criteria

A **generating unit** or **aggregated generating facility** must, in order to meet the exemption criteria referred to in requirement R4 of this **reliability standard**:

(a) be a wind **aggregated generating facility**;

(b) not be equipped with a **voltage regulating system**; and

(c) be the subject of an executed *Construction Commitment Agreement* and have completed the **ISO**'s approval process for connection to the **transmission system** under the *Technical Requirements for connecting generators (1999)*.

Alberta Reliability Standard
Generator Operation for Maintaining Network Voltages
VAR-002-AB-3

1. Purpose

To ensure **generating units** and **aggregated generating facilities** provide reactive support and voltage control, within generating facility capabilities, in order to protect equipment and maintain reliable operation of the **Interconnection**.

2. Applicability

This **reliability standard** applies to:

(a) the **legal owner** of a **generating unit**, including a **generating unit** that operates as a synchronous condenser, that:

(i) is not part of an **aggregated generating facility**;

(ii) has a **maximum authorized real power** rating greater than 4.5 MW; and

(iii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(b) the **operator** of a **generating unit**, including a **generating unit** that operates as a synchronous condenser, that:

(i) is not part of an **aggregated generating facility**;

(ii) has a **maximum authorized real power** rating greater than 4.5 MW; and

(iii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(c) the **legal owner** of an **aggregated generating facility** that:

(i) has a **maximum authorized real power** rating greater than 4.5 MW; and

(ii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and

(d) the **operator** of an **aggregated generating facility** that:

(i) has a **maximum authorized real power** rating greater than 4.5 MW; and

(ii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat.

Notwithstanding subsections (c) and (d) above, this **reliability standard** does not apply to the **legal owner** of an **aggregated generating facility** or the **operator** of an **aggregated generating facility** that meets the criteria listed in Appendix 1 of VAR-001-AB.

Requirements

R1 The **operator** of a **generating unit** and the **operator** of an **aggregated generating facility** must, while a **generating unit** or **aggregated generating facility** is electrically connected to the **transmission**

system, operate the **generating unit** or **aggregated generating facility** with its **automatic voltage regulator** or **voltage regulating system** in service and in voltage control mode unless:

a) exempted by the **ISO**;

b) the **operator** of the **generating unit** or **operator** of the **aggregated generating facility** provides voice notification to the **ISO** of its intention to operate the **generating unit** or **aggregated generating facility** otherwise;

c) the **generating unit** or **aggregated generating facility** is being operated in start-up or shut-down mode in accordance with the procedure of the **operator** of a **generating unit** or **operator** of an **aggregated generating facility**; or

d) the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** has previously obtained approval from the **ISO** allowing the **generating unit** or **aggregated generating facility** to be in a testing mode.

R2 Unless exempted by the **ISO**, each **operator** of a **generating unit** and each **operator** of an **aggregated generating facility** must, upon receiving an instruction from the **ISO** regarding voltage levels or **reactive power**, comply with that instruction.

R2.1 Each **operator** of a **generating unit** and each **operator** of an **aggregated generating facility** must, when:

a) the **automatic voltage regulator** of a **generating unit** or the **voltage regulating system** of an **aggregated generating facility** is out of service; or

(b) the **generating unit** does not have an **automatic voltage regulator**, or the **aggregated generating facility** does not have a **voltage regulating system**,

use an alternative method to control the generator reactive output to comply with an instruction from the **ISO** regarding voltage levels or **reactive power**.

R2.2 Notwithstanding requirement R2, where the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** cannot comply with an instruction to modify voltage, the **operator** of a **generating unit** or the **operator** of an **aggregated generating facility** must provide an explanation for why the instruction cannot be met.

R2.3 Each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** that does not monitor the voltage or **reactive power** at the location specified in an instruction from the **ISO**, or at the location specified in a **directive** issued by the **ISO** in accordance with section 301.2 of the **ISO rules**, *ISO Directives*, must have a methodology for converting the voltage or **reactive power** at the location specified by the **ISO**.

R3 Each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** must notify the **ISO** within thirty (30) minutes after a status change of the **automatic voltage regulator**, **voltage regulating system** or alternative voltage controlling device and power system stabilizer, as applicable, on any **generating unit** or **aggregated generating facility**.

R3.1 If the status has been restored within thirty (30) minutes of such change, then the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** is not required to notify the **ISO** of the status change.

R3.2 If a **generating unit** or an **aggregated generating facility** is in testing, start-up, shut-down or offline mode, requirement R3 does not apply.

R4 Each **operator** of a **generating unit** and **operator** of an **aggregated generating facility** must notify the **ISO** within thirty (30) minutes after becoming aware of a change in reactive capability due to factors other than a status change described in requirement R3.

R4.1 If the capability has been restored within thirty (30) minutes of the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** becoming aware of such change, then the **operator** is not required to notify the **ISO** of the change in reactive capability.

R4.2 If a **generating unit** or an **aggregated generating facility** is in testing, start-up, shut-down or offline mode, requirement R4 does not apply.

R5 Each **legal owner** of a **generating unit** and each **legal owner** of an **aggregated generating facility** whose step-up transformer for connecting to the **transmission system** or auxiliary transformer has primary voltages equal to or greater than the **generating unit** terminal voltage must provide any one (1) or more of the following to the **ISO** within thirty (30) **days** of a request:

a) tap settings;

b) available fixed tap ranges; and

c) impedance data.

R6 Each **legal owner** of a **generating unit** and each **legal owner** of an **aggregated generating facility** that has a step-up transformer, with off-load taps for connecting to the **transmission system** must, change the tap positions according to the specifications the **ISO** provides.

R6.1 Each **legal owner** of a **generating unit** and each **legal owner** of an **aggregated generating facility** that cannot comply with requirement R6 must notify the **ISO** within thirty (30) **days** of the **ISO** providing the specifications, and must include the technical justification along with the notice.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of operating the **generating unit** or **aggregated generating facility** in automatic voltage control mode as required in requirement R1 exists. Evidence may include, but is not limited to, exemption letters, data files, start-up or shut-down procedures, **operator** logs, voice recordings, e-mail, or other equivalent evidence.

MR2 Evidence of complying with an instruction as required in requirement R2 exists. Evidence may include, but is not limited to, data files or **operator** logs.

MR 2.1 Evidence of using an alternative method to control generator **reactive power** output as required in requirement R2.1 exists. Evidence may include, but is not limited to, data files, **operator** logs or voice recordings.

MR 2.2 Evidence of providing an explanation to the **ISO**, as required in requirement R2.2 exists. Evidence may include, but is not limited to, voice recordings or **operator** logs.

MR 2.3 Evidence of having a methodology as required in requirement R2.3 exists. Evidence may include, but is not limited to, a documented methodology or other equivalent evidence.

MR3 Evidence of notifying the **ISO** within thirty (30) minutes of any status change as required in requirement R3 exists. Evidence may include, but is not limited to, data logs, SCADA logs, voice recordings or **operator** logs.

MR4 Evidence of notifying the **ISO** within thirty (30) minutes of becoming aware of a change in capability as required in requirement R4 exists. If the capability has been restored within the first thirty (30) minutes of the **operator** of a **generating unit** or **operator** of an **aggregated generating facility** becoming aware of such change, no evidence of notification is necessary. Evidence may include, but is not limited to, voice recordings or **operator** logs.

MR5 Evidence of providing the **ISO** with information on its step-up transformer or auxiliary transformer, as required in requirement R5 exists. Evidence may include, but is not limited to, dated written or electronic records.

MR6 Evidence of changing step-up transformer taps in accordance with the **ISO**'s specifications as required in requirement R6 exists. Evidence may include, but is not limited to, written or electronic records.

MR6.1 Evidence of notifying the **ISO** as required in requirement R6.1 exists. Evidence may include, but is not limited to, written or electronic notifications.

Revision History

Date	Description
2013-10-01	Initial release
2016-04-01	Revised to align with NERC version 3.

Alberta Reliability Standard
Automatic Voltage Regulators and Voltage Regulating Systems
VAR-002-WECC-AB-1

1. Purpose

The purpose of this **reliability standard** is to ensure that:

(a) **automatic voltage regulators** on **generating units** and synchronous condensers are in service and controlling voltage; and

(b) **voltage regulating systems** at **aggregated generating facilities** are in service and controlling voltage.

2. Applicability

This **reliability standard** applies to:

(a) the **operator** of a **generating unit**, including those that operate as a synchronous condenser, that:

(i) is not part of an **aggregated generating facility**;

(ii) has a **maximum authorized real power** rating greater than four point five (4.5) MW; and

(iii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(b) the **operator** of an **aggregated generating facility** that:

(i) has a **maximum authorized real power** rating greater than four point five (4.5) MW; and

(ii) is directly connected to either the **transmission system** or to **transmission facilities** within the City of Medicine Hat; and

(c) the **operator** of a **transmission facility** that operates a synchronous condenser.

3. Requirements

R1 Each **operator** of a **generating unit**, **operator** of an **aggregated generating facility** and **operator** of a **transmission facility** that operates a synchronous condenser, must have the **automatic voltage regulator** or **voltage regulating system** in service and in automatic voltage control mode for ninety-eight percent (98%) of all operating hours except that the operating hours determined in accordance with requirements R1.1 through R1.12 inclusive may be extended to achieve the ninety-eight percent (98%) requirement.

R1.1 The operating hours during which the **generating unit**, **aggregated generating facility** or synchronous condenser operates for less than five percent (5%) of all hours during any calendar quarter;

R1.2 The operating hours during which maintenance or testing on any of the foregoing was performed, up to a maximum of seven (7) calendar **days** per calendar quarter;

R1.3 The operating hours during which the **automatic voltage regulator** or **voltage regulating system** exhibits instability due to an abnormal system configuration;

R1.4 The operating hours, up to a maximum of sixty (60) consecutive **days** per incident, during which the **automatic voltage regulator** or **voltage regulating system** is out of service for repair due to component failure;

R1.5 The operating hours, up to a maximum of twelve (12) consecutive **months**, during which the **automatic voltage regulator** or **voltage regulating system** had a component failure, provided the **operator** of a **generating unit**, **operator** of an **aggregated generating facility** or **operator of a transmission facility** submitted documentation to the **ISO** identifying the need for time to obtain replacement parts and, if required, to schedule an **outage**;

R1.6 The operating hours, up to a maximum of twenty-four (24) consecutive **months** during which the **automatic voltage regulator** or **voltage regulating system** had a component failure, provided the **operator** of a **generating unit**, **operator** of an **aggregated generating facility** or **operator of a transmission facility** submitted documentation to the **ISO** identifying the need for time for replacement of the excitation system including replacing the **automatic voltage regulator** or **voltage regulating system**, limiters, and controls but not necessarily the power source and power bridge, and to schedule an **outage**;

R1.7 The operating hours during which the synchronous **generating unit**, **aggregated generating facility** or synchronous condenser is not in **commercial operation**;

R1.8 The operating hours for which the **ISO** has issued a **directive** to the **operator** of a **generating unit** to operate the **generating unit** when the **automatic voltage regulator** is unavailable for service;

R1.9 The operating hours for which the **ISO** has issued a **directive** to the **operator** of an **aggregated generating facility** to operate the **aggregated generating facility** when the **voltage regulating system** is unavailable for service;

R1.10 The operating hours for which the **ISO** has issued a **directive** to an **operator** of a **transmission facility** to operate a synchronous condenser when the **automatic voltage regulator** is unavailable for service;

R1.11 The operating hours during which an **automatic voltage regulator** exhibits instability due to operation of an on-load tap changer transformer in the area when the **ISO** has authorized the **operator** of a **generating unit** or **operator** of a **transmission facility** to operate the excitation system in modes other than automatic voltage control until the **transmission system** configuration changes; and

R1.12 The operating hours during which a **voltage regulating system** exhibits instability due to operation of an on-load tap changer transformer in the area when the **ISO** has authorized the **operator** of an **aggregated generating facility** to operate the **voltage regulating system** in modes other than automatic voltage control until the **transmission system** configuration changes.

R2 Each **operator** of a **generating unit**, **operator** of an **aggregated generating facility** and **operator** of a **transmission facility** must have documentation supporting the identification of the number of operating hours excluded for each requirement in requirements R1.1 through R1.12 inclusive.

4. Measures

MR1 Evidence of having the **automatic voltage regulator** or **voltage regulating system** in service and in automatic voltage control mode as required in requirement R1 exists. Evidence may include documentation that summarizes for each calendar quarter:

(a) the number of hours the **automatic voltage regulator** or **voltage regulating system** was in service and in automatic voltage control mode while the **generating unit**, the **aggregated generating facility** or synchronous condenser was operating;

(b) the number of hours the **automatic voltage regulator** or **voltage regulating system** was out of service while the **generating unit**, the **aggregated generating facility** or synchronous condenser was operating;

(c) the number of operating hours excluded in accordance with requirements R1.1 through R1.12; and

(d) the percentage of operating hours that the **automatic voltage regulator** or **voltage regulating system** was in service, excluding the number of operating hours determined in accordance with requirements R1.1 through R1.12.

MR2 Evidence of having documentation as required in requirement R2 exists. Evidence may include a document identifying the subject of each applicable exclusion, the date and the period of time that the exclusion refers to, reasons, the supporting data and the supporting logs.

Revision History

Effective	Description
2013-10-01	

Alberta Reliability Standard
Power System Stabilizer
VAR-501-WECC-AB-1

1. Purpose

The purpose of this **reliability standard** is to ensure that **power system stabilizers** on **generating units** are kept in service.

2. Applicability

This **reliability standard** applies to:

(a) the o**perator** of a **generating unit** equipped with a **power system stabilizer** that is either:

(i) directly connected to the **bulk electric system** or part of an industrial complex that is directly connected to the **bulk electric system**, and has a **maximum authorized real power** rating greater than eighteen (18) MW; or

(ii) within a power plant which:

(A) is not part of an **aggregated generating facility**;

(B) is directly connected to the **bulk electric system**; and

(C) has a combined **maximum authorized real power rating** greater than sixty-seven point five (67.5) MW;

(iii) a black start resource; or

(iv) regardless of **maximum authorized real power** rating, material to this **reliability standard** and to the **reliability** of the **bulk electric system** as the **ISO** determines and publishes on the AESO website and may amend from time to time in accordance with the process set out in Appendix 1.

3. Requirements

R1 Each **operator** of a **generating unit** equipped with a **power system stabilizer** must have the **power system stabilizer** in service ninety-eight (98%) of all operating hours except that the operating hours determined in accordance with requirements R 1.1 through 1.12 inclusive may be excluded to achieve the ninety-eight percent (98%) requirement.

R1.1 The operating hours during which the **generating unit** operates for less than five percent (5%) of all hours during any calendar quarter.

R1.2 The operating hours during which maintenance or testing on the **power system stabilizer** was performed, up to a maximum of seven (7) **days** per calendar quarter.

R1.3 The operating hours during which the **power system stabilizer** exhibits instability due to abnormal system configuration.

R1.4 The operating hours during which the **generating unit** is operating in the synchronous condenser mode and the **generating unit** is very near or at a zero (0) **real power** level.

R1.5 The operating hours during which the **generating unit** is generating less **real power** than its design limit for effective **power system stabilizer** operation.

R1.6 The operating hours during which the **generating unit** is passing through a range of output that is a known “rough zone” being a range in which a **generating unit** is experiencing excessive

vibration.

R1.7 The operating hours during which the **automatic voltage regulator** of the **generating unit** is not in service.

R1.8 The operating hours, up to a maximum of sixty (60) consecutive **days** per incident, during which the **power system stabilizer** is out of service for repair due to a component failure.

R1.9 The operating hours, up to a maximum of twelve (12) consecutive **months**, during which the **power system stabilizer** had a component failure, but only if the **operator** of a **generating unit** submitted documentation to the **ISO** identifying the need for time to obtain replacement parts and identifying a scheduled **outage**, if required.

R1.10 The operating hours, up to a maximum of twenty-four (24) consecutive **months**, during which the **power system stabilizer** had a component failure, but only if the **operator** of a **generating unit** submitted documentation to the **ISO** identifying the need for time to replace the **power system stabilizer** and to schedule an **outage**.

R1.11 The operating hours during which the **generating unit** is not in **commercial operation**.

R1.12 The operating hours for which the **ISO** has issued a **directive** to the **operator** of a **generating unit** to operate the **generating unit** when the **power system stabilizer** is unavailable for service

R2 Each **operator of a generating unit** must have documentation supporting the identification of the number of operating hours excluded for each requirement in requirements R1.1 through R1.12 inclusive.

4. Measures

The following measures correspond to the requirements identified in section 3 of this **reliability standard**. For example, MR1 is the measure for R1.

MR1 Evidence of having the **power system stabilizer** in service as required in requirement R1 exists. Evidence may include documentation that summarizes for each calendar quarter:

(a) the number of hours the **power system stabilizer** was in service while the **generating unit** was operating;

(b) the number of hours the **power system stabilizer** was out of service while the **generating unit** was operating;

(c) the number of operating hours excluded in accordance with requirements R1.1 through R1.12; and

(d) the percentage of operating hours that the **power system stabilizer** was in service excluding the number of operating hours determined in accordance with requirements R1.1 through R1.12

MR2 Evidence of having documentation as required in requirement R2 exists. Evidence may include a document identifying the subject of each exclusion, the date and the period of time that the exclusion refers to, reasons, the supporting data and the supporting logs.

5. Appendices

Appendix 1 – *Amending Process for List of Generating Units*

Revision History

Effective	Description
2013-10-01	

Appendix 1

Amending Process for List of Generating Units

In order to amend the list referenced in subsection (a)(iv) of section 2, *Applicability*, the **ISO** must:

(a) upon determining that a **generating unit** is to be added, notify each affected **operator** of a **generating unit** in writing and determine an effective date, which must be no less than thirty (30) **days** after the date of notice, for the **operator** to meet the applicable requirements;

(b) upon determining that a **generating unit** is to be deleted, notify each affected **operator** of a **generating unit** in writing and determine an effective date for the **operator** to no longer be required to meet the applicable requirements; and

(c) post the amended list with effective dates on the AESO website.