



AESO Reliability Committee (ARC)

May 14, 2010
Alberta Electric System Operator
2500, 330 5th Avenue SW
8:00 am – 12:00 noon

Agenda

1. Action items from last meeting

Jerry Mossing

- a. Requested changes to TOR by ARC representatives
- b. EOP-005 Action Item
 - i. [ID – 2010 Restoration Plans and Blackstart Procedures](#)
 - ii. [EOP – 005 – AB – 2 System Restoration from Blackstart Resources](#)
- c. PRC-018 Action Item
 - i. [ID - Disturbance Monitoring Equipment Locations](#)
- d. PRC related material
 - i. [Classification of Remedial Action Schemes and Applicability to Reliability Standards](#)
 - ii. [PRC-005-AB-1](#)
 - iii. [Status of PRC Standards](#)

2. Standards effective dates

Mike Law

3. Standards template change (TOAD)

Doug Hincks

4. Standards recommendations from workgroups

Jerry Mossing/
Neil Curtis/Doug
Hincks

• Operations

- [COM-001-AB-1.1](#)
- [COM-002-AB-2](#)
- [IRO-005-AB-3](#)
- [MOD-010&012-AB-0](#)
- [PER-003-AB-0](#)
- [PER-005-AB-1](#)
- [PRC-007-AB-0](#)
- [PRC-008-AB-0](#)
- [PRC-011-AB-0](#)
- [PRC-017-AB-0](#)

5. Standards that are being recommended to be rejected for application in Alberta

Jerry Mossing

- Operations
 - [IRO-004-2](#)
 - [MOD-011-0](#)
 - [MOD-028-1](#)
 - [MOD-030-1](#)
 - [PER-002-0](#)
 -

6. Authoritative source for ARS documents Jerry Mossing

7. Discussion, Future meeting dates Jerry Mossing



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[Insert date here]

To: Market Participants and Interested Persons

Re: (Information Document # 2010-?? Restoration Plans and Blackstart Procedures

The AESO has prepared the attached information document to provide entities with a description of what elements should be considered when checking whether a restoration plan or blackstart procedure is consistent with the Alberta Interconnected Electric System Power System Restoration Plan.

This information document is likely of most interest to those entities that are defined in the applicability section of EOP-005-AB-2.

Sincerely

Mike Law, Vice-President- Operations

Comments/Questions

If you have any comments or questions about the information in this document please contact:

Doug Hincks

Title, Department

Phone #

e-mail:

Market participants are advised that the contents of this ID are for information purposes only and are intended to provide guidance. ID content is therefore subject to change from time to time. For an understanding of the governing legal and binding requirements and obligations on any referenced subject matter, please consult the actual Authoritative Document language within the relevant ISO rules, Tariff and Reliability Standards.

1) Purpose

This information document supports Alberta Reliability Standard EOP-005-AB-2. The purpose of this document is to provide entities with a description of what elements should be considered when checking whether a restoration plan or blackstart procedures is consistent with the Alberta Interconnected Electric System Power System Restoration Plan. (Alberta Interconnected Electric System Power System Restoration Plan). This information document is likely of most interest to those entities that are defined in the applicability section of EOP-005-AB-2.

2) Elements Necessary for Restoration Plans and Blackstart Procedures to be Consistent with the Alberta Interconnected Electric System Power System Restoration Plan

The information below can be used to test for consistency between restoration plans or blackstart procedures and the Alberta Interconnected Electric System Power System Restoration Plan.

2.1 TFO Restoration Plans

The following are items for a transmission facility owner to consider when evaluating whether their restoration plan is consistent with the Alberta Interconnected Electric System Power System Restoration Plan.

- The responsibilities detailed in the transmission facility owner restoration plan includes the responsibilities for transmission facility owners detailed in section 2.3 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The guidelines detailed in the transmission facility owner restoration plan are aligned with the guidelines in section 3 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The system restoration island strategies detailed in the transmission facility owner restoration plan are based on and support the Alberta Interconnected Electric System restoration island strategies detailed in section 4 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The system restoration processes detailed in the transmission facility owner restoration plan are aligned with the system restoration process detailed in section 5 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The contacts in the telephone contact list in the transmission facility owner restoration plan, where the same contacts exist in the Alberta Interconnected Electric System Power System Restoration Plan telephone contact list, contains the same phone number, unless it is found by the transmission facility owner that a

phone number or numbers in the contact list in the Alberta Interconnected Electric System Power System Restoration Plan is/are out of date;

2.2 Wire Owner Restoration Plans

The following are items for a wire owner to consider when evaluating whether their restoration plan is consistent with the Alberta Interconnected Electric System Power System Restoration Plan.

- The responsibilities detailed in the wire owner restoration plan includes the responsibilities for wire owners detailed in section 2.3 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The guidelines detailed in the wire owner restoration plan are aligned with the guidelines in section 3 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The system restoration island strategies detailed in the wire owner restoration plan are based on and support the Alberta Interconnected Electric System restoration island strategies detailed in section 4 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The system restoration processes detailed in the wire owner restoration plan are aligned with the system restoration process detailed in section 5 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The contacts in the telephone contact list in the wire owner restoration plan, where the same contacts exist in the Alberta Interconnected Electric System Power System Restoration Plan telephone contact list, contains the same phone numbers, unless it is found by the wire owner that a phone number or numbers in the contact list in the Alberta Interconnected Electric System Power System Restoration Plan is/are out of date;

2.3 Operator of a Generating Unit Blackstart Procedure

The following are items for an operator of a generating unit to consider when evaluating whether their blackstart procedure is consistent with the Alberta Interconnected Electric System Power System Restoration Plan.

- The responsibilities detailed in the blackstart procedure includes the responsibilities for operators of generating units detailed in section 2.3 of the Alberta Interconnected Electric System Power System Restoration Plan;



INFORMATION DOCUMENT (ID) TITLE

- The blackstart procedure is aligned with the guidelines in section 3 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The blackstart procedure is based on and supports the Alberta Interconnected Electric System restoration island strategies detailed in section 4 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The blackstart procedure is aligned with the system restoration process detailed in section 5 of the Alberta Interconnected Electric System Power System Restoration Plan;
- The contacts in the telephone contact list in the blackstart procedure, where the same contacts exist in the Alberta Interconnected Electric System Power System Restoration Plan telephone contact list, contains the same phone numbers, unless it is found by the operator of a generating unit that a phone number or numbers in the contact list in the Alberta Interconnected Electric System Power System Restoration Plan is/are out of date;

Revision History

Version	Effective Date	Description of Changes
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Comments/Questions

If you have any comments or questions about the information in this document please contact:

Doug Hincks

Title, Department

Phone #

e-mail:

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EOP – 005 – AB – 2 System Restoration from Blackstart Resources

Purpose

The purpose of this *reliability standard* is to ensure plans, facilities, and personnel are prepared to enable the restoration of the *AIES* in the event of a complete or partial *blackout* of the *AIES*.

Applicability

This *reliability standard* applies to the entities listed below:

- *ISO*
- *TFOs*
- *WOs*
- ~~GFOs~~ Generator operators ~~Operators of generating units~~ with an aggregate *generating unit* capacity greater than 40MW within a *power plant*, but excluding ~~all operators of~~ distribution connected generating units ~~GFOs~~ generator operators and ~~all~~ wind generating units ~~GFOs~~ generator operators.

In this reliability standard, the term “system restoration participant” means all those that are listed above.

Definitions

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

Requirements

- R1. The *ISO* must have an *AIES* ~~PSRP~~ Power System Restoration Plan to restore the *AIES* in the event of a complete or partial *blackout* of the *AIES*. The *AIES* ~~PSRP~~ Power System Restoration Plan must include or incorporate by reference, without limitation, the following:
 - R1.1 The roles and responsibilities of ~~system restoration participants~~ system restoration participants during a restoration event.
 - R1.2 Staffing levels and deployment strategies of *ISO* personnel required to implement the *AIES* ~~PSRP~~ Power System Restoration Plan.
 - R1.3 *System restoration guidelines* for restoring *interconnections* with the other *interconnected transmission operators*.

- R1.4** Identification of each *blackstart resource* and its characteristics including, without limitation, the following: the name of the *blackstart resource*, the name of the *blackstart generator(s)*, the type of unit, the MCR and the *generating unit* capability curve(s) with all limiting characteristics.
- R1.5** *System restoration strategies* for restoring the *AIES*.
- R1.6** Identification of acceptable operating voltage and frequency limits during restoration.
- R1.7** *System restoration guidelines* for synchronization to reestablish connections for areas that have been restored and are prepared for reconnection.
- R1.8** *System restoration guidelines* to restore loads.
- R1.9** A list of *critical loads* as defined by the *ISO* ~~which may include~~including, without limitation, the following: the name of the load, the reason for *critical load* status, the point of interconnection by substation and feeder, the peak MVA of the feeder from which the *critical load* is supplied and if the *load* has on-site emergency generation.
- R1.10** Processes for transferring ~~system restoration participants~~system restoration participant roles and responsibilities from one ~~system restoration participants~~system restoration participant to another.
- R1.11** Voice communication protocols and information logging protocols.
- R1.12** A change management process to review, update and distribute the *AIES PSRP*Power System Restoration Plan.
- R2** The *ISO* must submit the *AIES PSRP*Power System Restoration Plan to the *VRC* and *interconnected transmission operators*.
- R3** Each *TFO* and *WO* must develop a restoration plan for its portion of the *AIES*.
- R4** Each ~~GFO~~operator of a generating unit generator operator must develop a blackstart procedure(s) for its generating facility.
- R5** Each *TFO*, ~~GFO~~operator of a generating unit generator operator and *WO* must develop its restoration plan or blackstart procedure(s) in coordination with their respective interconnected ~~system restoration participants~~system restoration participants.
- R6** Each *TFO* restoration plan must be consistent with the *AIES PSRP*Power System Restoration Plan and must include or incorporate by reference, without limitation, the following:
 - R6.1** Staffing levels, personnel contact information, deployment strategies for operations and field personnel and the associated roles and responsibilities of the personnel required to implement the *TFO* restoration plan.
 - R6.2** *System restoration strategies* for restoring its portion of the *AIES* including, without limitation, initial switching requirements of the *cranking paths* (primary and secondary) from each *blackstart resource* to the first *generating unit* planned to be brought on-line. These *system restoration strategies* must include the recognition that the switching requirements may change depending on the initial *blackout* conditions.
 - R6.3** Lists of *critical loads*, as identified by the *ISO*, ~~including, without limitation, the following: the name of the load, the reason for critical load status, the point of interconnection by substation and feeder, the peak MVA of the feeder from which the critical load is supplied and if the load has on-site emergency generation.~~
 - R6.4** *System restoration guidelines* for portable generator deployment to remediate the loss of backup power at *transmission facilities* during a restoration event.

- R6.5** Voice communication protocols and information logging protocols.
- R6.6** Processes for transferring ~~system restoration participants~~ system restoration participant roles and responsibilities from one ~~system restoration participants~~ system restoration participant to another.
- R6.7** Real-time emergency and normal operations operator contact information for the ISO and interconnected entities.
- R7** Each *WO* restoration plan must be consistent with *AIES* ~~PSRP~~ Power System Restoration Plan and must include or incorporate by reference, without limitation, the following:
 - R7.1** Staffing levels, personnel contact information, deployment strategies for operations and field personnel and the associated roles and responsibilities of the personnel required to implement the *WO* restoration plan.
 - R7.2** *System restoration strategies* for restoring its portion of the *AIES*.
 - R7.3** Lists of *critical loads*, as identified by the *ISO*, ~~including, without limitation, the following: the name of the load, the reason for critical load status, the point of interconnection by substation and feeder, the peak MVA of the feeder from which the critical load is supplied and if the load has on-site emergency generation.~~
 - R7.4** *System restoration guidelines* for portable generator deployment to remediate the loss of backup power at *transmission facilities* during a restoration event.
 - R7.5** Voice communication protocols and information logging protocols.
 - R7.6** Processes for transferring ~~system restoration participants~~ system restoration participant roles and responsibilities from one ~~system restoration participants~~ system restoration participant to another.
 - R7.7** Real-time emergency and normal operations operator contact information for the ISO and interconnected entities.
- R8** ~~GFOs~~ Operators of generating units ~~Generator operator~~ must have blackstart procedures to restart or reconnect *generating units* ~~must be~~ consistent with the *AIES* ~~PSRP~~ Power System Restoration Plan and ~~must~~ include or incorporate by reference, without limitation, the following:
 - R8.1** Staffing levels, personnel contact information, associated roles and responsibilities and deployment strategies of personnel required to implement the blackstart procedure.
 - R8.2** *Generating unit* capability curves including superimposed control, limiter and protection curves.
 - R8.3** Steps on how the *generating unit* must be energized and/or reconnected to the *AIES*.
 - R8.4** Voice communication protocols and information logging protocols.
 - R8.5** Real-time emergency and normal operations operator contact information for the ISO and interconnected entities.
- R9** The *ISO* must review, update and distribute the *AIES* ~~PSRPP~~ Power System Restoration Plan ~~annually once per calendar year~~ or more frequently if system modifications dictate. If there are no changes to the previously distributed *AIES* ~~PSRP~~ Power System Restoration Plan the *ISO* must confirm to the ~~system restoration participants~~ system restoration participants, *VRC* and *interconnected transmission operators* that the *AIES* ~~PSRP~~ Power System Restoration Plan has been reviewed and no changes were necessary.

- R10** Each TFO, ~~GFO~~ operator of a generating unit~~generator operator~~ and WO, within 90 days following the ISO review of the AIES PSRP and upon request by the AESO, must review and update, as required, its restoration plan or blackstart procedures. If a restoration plan or blackstart procedures is updated, it, and all referenced documents, must be submitted to the ISO within the same 90 day period. If there is no update required to the restoration plan or blackstart procedures the TFOs, ~~GFOs~~ operators of generating units~~generator operators~~, and WOs must provide written confirmation to the ISO within the same 90 day period that it has reviewed its restoration plan or blackstart procedures and no updates were necessary.
- R11** Each system restoration participant must have a copy of the ~~AIES PSRP~~ Power System Restoration Plan and its restoration plan or blackstart procedures within its primary and backup control rooms and available to all of its control room operators.
- R12** The ISO and each *blackstart service provider*, as designated in the ~~AIES PSRPP~~ Power System Restoration Plan, must have entered into a written agreement between them for the provision of *blackstart service* by the *blackstart service provider* to the AESO specifying the terms and conditions of their arrangement including, without limitation, the following: requirements for training, *blackstart resource* testing and *blackstart resource* capability notification.
- R13** The ISO must, not less than once every 5 years, verify through analysis of actual events, engineering studies, or testing, or any combination thereof, the following:
- R13.1** 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.
- R13.2** The location and magnitude of *loads* required to control voltages and frequency within operating limits.
- R13.3** The capability of *generating units* required to control voltages and frequency within acceptable operating limits.
- R14** Each system restoration participant must implement its restoration plan or blackstart procedures following a *system controller* declared partial or complete *blackout* of the AIES.
- R15** Each system restoration participant must provide ~~annual~~ training at least once per calendar year on its restoration plan or blackstart procedure to any personnel who are required to implement its restoration plan or blackstart procedures to ensure that the personnel can implement the restoration plan or blackstart procedure.
- R16** The ISO must schedule and conduct restoration drills, exercises or simulations at least once per calendar year and must provide 90 days prior notice to each system restoration participant of the date and location of such drills, exercises or simulations. ~~System restoration participants~~ System restoration participants must ~~ensure that personnel referred to in R15~~ ensure that personnel referred to in R15 participate in the restoration drills, exercises or simulations as requested ~~as and~~ and scheduled by the ISO.

Processes and Procedures

All processes and procedures for this *reliability standard* are included in the restoration plans or blackstart procedures.

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** *AIES PSRP* exists and contains the content specified in requirements R1.1 to R1.12 and that the content is reasonable.
- MR2** Written evidence exists that the *ISO* has submitted the *AIES PSRP* to the *VRC* and *interconnected transmission operators*.
- MR3** Restoration plans exist.
- MR4** Blackstart procedures exist.
- MR5** Written confirmation stating that the restoration plans or blackstart procedures have been coordinated with that interconnected system restoration participant.
- MR6** Each *TFO* restoration plan is consistent with the *AIES PSRPPower System Restoration Plan* and, contains the content specified in requirements R6.1 to R6.7 ~~and that the content is reasonable.~~
- MR7** Each *WO* restoration plan is consistent with the *AIES PSRPPower System Restoration Plan* and, contains the content specified in requirements R7.1 to 7.7 ~~and that the content is reasonable.~~
- MR8** ~~Each GFO operator of a generating unit generator operator, p~~ Procedures ~~(s) is are~~ consistent with the *AIES PSRP-Power System Restoration Plan* and, contains the content specified in requirements R8.1 to 8.5 ~~and that the content is reasonable.~~
- MR9** Evidence exists that shows actions were completed, as specified in requirement R9.
- MR10** Evidence exists that shows actions were completed, as specified in requirement R10.
- MR11** Documentation exists in the physical locations as specified in requirement R11.
- MR12** Agreement exists with the content as specified in requirement R12.
- MR13** Documentation, such as load flow studies and dynamic simulations, and other supporting evidence exists and shows that the actions were performed in the time line as specified in requirement R13 to R13.3.
- MR14** Evidence exists that shows ~~system restoration participants~~ system restoration participants have implemented restoration plans or blackstart procedures as specified in requirement R14.
- MR15** Evidence exists that shows parties have provided training as specified in requirement R15.
- MR16** Evidence exists that shows activities have been completed as specified in requirement R16.

Appendices

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

Guidelines

System restoration guidelines for this *reliability standard* are included in the restoration plans.

Revision History

Effective	Description
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2008-00-00	
2008-00-00	

Proposed Terms for the ARS Glossary Definitions

This section is used for information purposes only and will not be included in the final draft version that is filed with the Alberta Utilities Commission (AUC).

- “*AIES PSRP*” means the power system restoration plan the requirements of which are described in EOP-005-AB-2.
- “*blackstart generating unit*” means a *generating unit* that is able to start without any source of off-site electric power and that is capable of maintaining adequate voltage and frequency while energizing *transmission facilities* and *auxiliary loads* of other *generating units*.
- “*blackstart resource*” means the resources of any entity that has entered into a *blackstart service* agreement with the AESO.
- “***blackstart service***” has the same meaning as provided in the **Liability Protection Regulation**.
- “*cranking path*” means a portion of the electric system that can be isolated and then energized to deliver electric power from a *generating unit* to enable the startup of one or more other *generating units*.
- “*critical load*” means any electric *loads* that are essential to the restoration and operation of the *AIES*.
- ~~“*system restoration participants*” means the *ISO, TFOs, WOs and GFOs operators of generating units generator operators with an aggregate generating unit capacity greater than 40MW within one power plant but excluding all distribution connected generating units GFOs generator operators and all wind generating units GFOs generator operators.*~~
- “*system restoration strategies*” means a written plan that identifies transmission paths from generating facilities to *loads*, other generating facilities and island boundaries.
- “*system restoration guidelines*” means non-mandatory advisory information which a *system controller* or an operator may use to assist it in making approximate calculations or for predicting outcomes of proposed *AIES* restoration activities.



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[Insert date here]

To: Market Participants and Interested Persons

Re: Disturbance Monitoring Equipment Locations

(Insert brief description of the purpose of this ID)

Text

Text

Sincerely

(Name), (Title)

Comments/Questions

If you have any comments or questions about the information in this document please contact:

Name

Title, Department

Phone #

e-mail:

Market participants are advised that the contents of this ID are for information purposes only and are intended to provide guidance. ID content is therefore subject to change from time to time. For an understanding of the governing legal and binding requirements and obligations on any referenced subject matter, please consult the actual Authoritative Document language within the relevant ISO rules, Tariff and Reliability Standards.

1. Purpose

This information document supports the Alberta Reliability Standard PRC-018-AB-1 Disturbance Monitoring Equipment Installation and Data Reporting. The purpose of this document is to provide a list of disturbance monitoring equipment locations to TFOs and GFOs as required by the AESO.

2. Background

Alberta Reliability Standard PRC-018-AB-1 Disturbance Monitoring Equipment Installation and Data Reporting outlines the requirement for TFOs and GFOs to install disturbance monitoring equipment and to report disturbance data in accordance with regional requirements to facilitate the analysis of events. It also illustrates the AESO's requirement to maintain the list of disturbance monitoring equipment that applies to the reliability standard.

3. Appendices

Appendix 1 Disturbance Monitoring Equipment Locations

Alberta Standard PRC-018-AB-1 Disturbance Monitoring Equipment Locations		
Location	Owner	Type
Langdon 102S	Altalink	PMU
Empress 394S	Altalink	PMU
Sundance 310P	Altalink	PMU
Ruth Lake 848S	ATCO	PMU

Revision History

Version	Effective Date	Description of Changes
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Comments/Questions

If you have any comments or questions about the information in this document please contact:

Name
Title, Department
Phone #
e-mail:

Classification of Remedial Action Schemes and Applicability to Reliability Standards

The purpose of this document is to identify the process and criteria to classify remedial action schemes (RAS) and to identify the application of the RAS classifications to reliability standards.

This document identifies:

- the process to classify RASs.
- the classification criteria for all RASs including:
 - o legacy RASs previously listed in OPP 704,
 - o new RASs and
 - o modified RASs
- the applicability of RASs to reliability standards based on the RAS classification.
- the data and documentation required for RASs to meet the anticipated requirements of PRC-015-AB-0¹.

The ISO has also developed a supplemental reference document, “AB RAS Overview Paper“, that correlates the WECC and NERC classifications of RASs with that being proposed for Alberta.

1. Classification Process

Each RAS listed in OPP 704, all new RAS and modified existing RAS will be classified in accordance with the process flowchart in Figure 1:

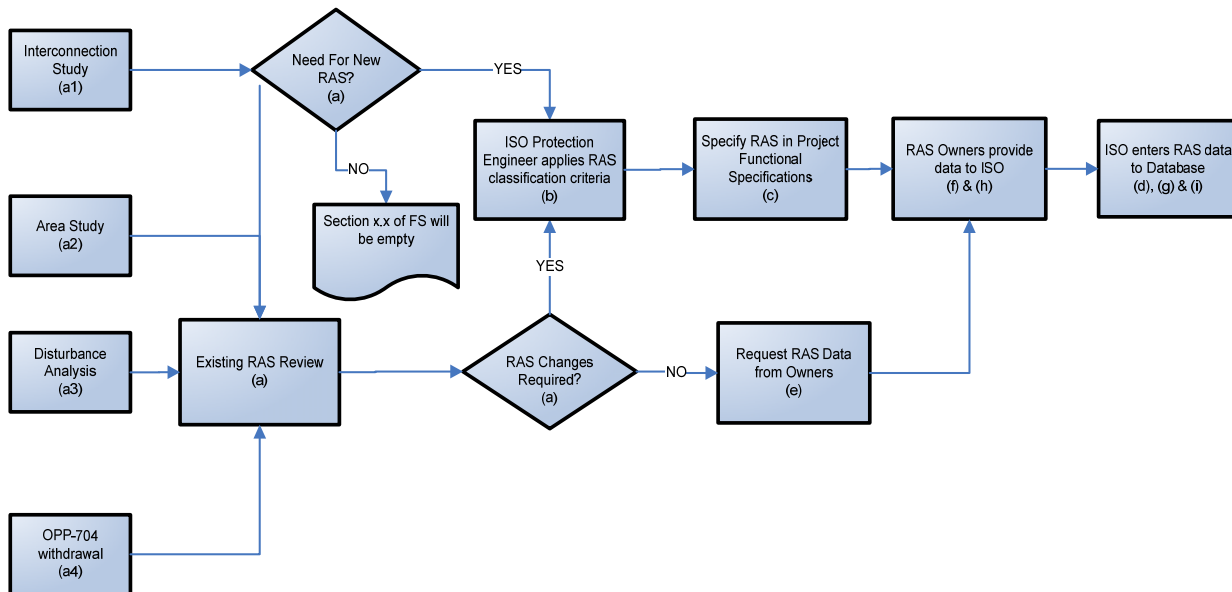


Figure 1: Process Flowchart of RAS Classification

¹ This reliability standard is currently under development.

The steps in Figure 1 illustrate the process described below:

- a. The ISO triggers for classifying a remedial action scheme includes:
 1. Withdrawal of OPP-704 for review of existing RAS.
 2. Interconnection studies for review of existing RAS or need for new RAS.
 3. Area operations studies for review of existing RAS or need for new RAS.
 4. Disturbance analysis for review of existing RAS.
- b. The ISO protection engineer applies classification criteria.
- c. The ISO informs affected market participant of the RAS classification.
- d. The ISO enters RAS data into the database for schemes identified in OPP 704.
- e. The ISO requests RAS owners to submit data for all existing schemes identified in OPP-704.
- f. RAS owners complete and submit information as identified in Appendix 1 to the ISO.
- g. The ISO enters revised RAS data into the database.
- h. The ISO and RAS owners will collect RAS data for schemes as part of a new project functional specification using the interconnection / system gate process.
- i. The ISO will update and maintain the database for RASs that are in service.

At the conclusion of the process, each RAS listed in OPP 704, all new RAS, and modified RAS will be assigned a classification as a type of RAS. The RAS type will be used to determine applicability within reliability standards.

2. Classification Criteria

Each RAS listed in OPP 704, all new and modified RAS will be assigned into a group of RAS, by the ISO protection engineer, according to its primary function and the consequence of its failure using the criteria in sections 2.1 and 2.2. Each group of RAS is then classified according to Table 1 as a RAS type.

2.1 RAS Primary Function

A RAS is designed to protect equipment and/or mitigate a specific transmission system condition. RASs protect equipment and/or the power system from the effects of under/over voltage or frequency. RASs can also act to trip generator breakers in an islanded part of the power system or act as a safety net to meet Category D² performance. Assignment of RASs into groups will be based on the primary function of the RAS according to the following:

- a. ensure compliance with Category A, B and C² performance by:
 - shedding generation and/or load to:
 - mitigate the effects of credible contingencies to neighbouring balancing authority's control area and or an interconnection point
 - mitigate system stability concerns

² Category A, B, C & D are NERC/WECC/AESO terminology for system operating under zero (N-0), one (N-1), two (N-1-1 or N-2) and more than two (N-1-2 or more) elements out of service.

- mitigate equipment overloads above nominal and emergency ratings
 - reconfiguring the system
- b. protect equipment from over voltage
- c. protect generator and/or load when a part of the area system is reasonably expected to be islanded from the transmission system
- d. protect motors from thermal damage due to an under voltage condition
- e. reduce risk of complete system collapse by providing a load shedding safety net

2.2 Consequences of RAS Failure

If a RAS fails to perform its function when needed, it will affect the operation of the power system depending on the system conditions at the time. Based on the location and function of the RAS, consequences of its failure will also be used to assign RASs into groups. The consequences can be:

- a. system performance criteria violations
- b. local area performance criteria violations
- c. equipment failure
- d. inadequate power quality to load customers

2.3. Classification of RAS Type

Each RAS group is classified according to RAS type as indicated in Table 1, below:

Table 1: RAS Groups based on functionality and associated Type

Group	Group Name	Functional Objective	RAS Type	Comments
1	Interconnection RAS	Comply with Category A, B & C performance for interconnection with other balancing authorities	WECC RAS	Listed as RAS with WECC
2.1	UFLS	Mitigate consequences of extreme contingencies	Safety Net	UFLS is a system wide program
2.2	UVLS	Mitigate consequences of extreme contingencies	Safety Net	UVLS is a system or local area wide program
2.3	Out of step protection	Mitigate consequences of extreme contingencies	LAPS	Apply protection related ARS
3	Stability or overload protection or specific UVLS	Comply with Category A, B & C performance of the 240 kV and higher nominal voltage AIES	AB RAS	Apply same standard as for WECC registered RAS
4	Stability or overload protection or specific UVLS	Comply with Category A, B & C performance for the 138 kV and lower nominal voltage AIES	LAPS	Apply protection related ARS

Group	Group Name	Functional Objective	RAS Type	Comments
5	Over voltage protection	Protect equipment from over voltage	LAPS	Apply protection related ARS
6	Anti islanding protection	Protect generator and/or load in an islanded area system from under and over voltage and frequency.	LAPS	Apply protection related ARS
7	Under voltage protection	Protect motors from low voltage	LAPS	Apply protection related ARS
8	Generator protection	Protect generator from under voltage or under frequency	LAPS	Apply protection related ARS

3.0 Applicability within Reliability Standards

Table 2 is a reference guide to determine applicability of the types of RAS within the reliability standards that are related to protection, remedial action schemes and safety nets.

Table 2: Applicability of RAS Type within Reliability Standards

Reliability Standard	RAS Type				
	LAPS ³	AB RAS ⁴	WECC RAS ⁵	Safety Nets ⁶	
				UFLS	UVLS
<i>RAS Group</i> →	2,3, 4, 5, 6, 7 & 8	3	1	2.1	2.2
PRC-001-AB-1 Protection System Coordination	Y	Y	Y	Y	Y
PRC-004-AB-1 Analysis and Mitigation of Transmission. And Generation Protection System Misoperation	Y				
PRC-004-WECC-AB-1 Protection System and Remedial Action Scheme Misoperation			Y		
PRC-005-AB-1 ⁷ Transmission and Generation Protection System Maintenance and Testing	Y				
PRC-007-AB-0 ⁷ Assuring Consistency of Entity Under Frequency Load Shedding Program				Y	

³ LAPS is defined as Local Area Protection; can be called Local Area RAS as its failure only affects the local area performance.
⁴ A RAS whose failure to operate can affect 240 kV and above voltage system but not the adjacent Balancing Authority's system.
⁵ A RAS whose failure to operate can affect other adjacent Balancing Authority's system performance.
⁶ As defined in WECC documentation.
⁷ This reliability standard is currently under development.

Reliability Standard	RAS Type				
	LAPS ³	AB RAS ⁴	WECC RAS ⁵	Safety Nets ⁶	
				UFLS	UVLS
<i>RAS Group</i> →	2.3, 4, 5, 6, 7 & 8	3	1	2.1	2.2
PRC-008-AB-0' Implementation and Documentation of Under Frequency Load Shedding Equipment Maintenance Program				Y	
PRC-009-AB-0 UFLS Performance Following an Underfrequency Event				Y	
PRC-010-AB-0 Assessment of the Design and Effectiveness of UVLS Program					Y
PRC-011-AB-0' Under Voltage Load Shedding System Maintenance and Testing					Y
PRC-015-AB-0' Special Protection System Data and Documentation	Y	Y	Y	Y	Y
PRC-016-AB-0' Special Protection System Misoperations		Y			
PRC-017-AB-0' Special Protection System Maintenance and Testing		Y	Y		
PRC-021-AB-1 Under-Voltage Load Shedding Program Data					Y
PRC-022-AB-1 Under-Voltage Load Shedding Program Performance					Y
IRO-005-AB-3' Reliability Coordinator Current Day Operations			Y		

4. Data and Documentation

The RAS data and documentation will be stored in a database maintained by the ISO. The ISO proposes that this database contains the data described in section 4.1, documentation described in section 4.2 and any additional information necessary to manage RAS applications in Alberta. On a go-forward basis, data and documentation will be reviewed periodically and revised as appropriate.

The ISO will maintain the following data and documentation on each RAS listed in OPP 704, and all new and modified schemes; the party with responsibility to provide the data is indicated in brackets:

4.1 Data

- a. **Name:** Each RAS will be assigned a name **(ISO)**
- b. **Description:** Brief description of purpose of the scheme **(ISO)**
- c. **ISD:** Date the scheme was put in service **(ISO)**
- d. **Location:** Substation name and equipment number **(RAS Owner)**
- e. **Ownership:** List owner(s) of RAS equipment including communication/radio and final trip circuitry hardware that trip the breaker at TFO/GFO site. **(RAS Owner)**
- f. **Function:** Determined as per Section 2.1 **(ISO)**
- g. **Impact:** Consequences of failure as determined per Section 2.2; **(ISO)**
- h. **Group Number:** Determined as per Section 2. **(ISO)**
- i. **Group Name:** Determined as per Section 2. **(ISO)**
- j. **Type:** Determined as per Section 2.3 **(ISO)**
- k. **Trigger Event:** (Contingency Category (A, B, C or D) that is expected to trigger RAS operation (refer to Section 2.1) **(ISO)**
- l. **Reason:** Part of the interconnection or system performance requirement **(ISO)**
- m. **Status** (Temporary or Permanent): Some RASs are installed as part of the interconnection requirement due to the delay in transmission development. These RASs may be candidates for decommissioning after the related transmission development is in service. **(ISO)**
- n. **Transmission Project:** If the RAS is assigned a temporary status, list the name of the transmission project that will allow removal/decommissioning of the RAS **(ISO)**
- o. **Estimated Year of Removal:** Estimated year in which decommissioning may occur (depends on transmission project) **(ISO – optional)**

4.2 Documentation

- a. Diagram indicating ownership boundaries **(RAS Owner)**
- b. High level logic diagram showing the inputs, logic and trips **(RAS Owner)**
- c. RAS logic hardware **(RAS Owner)**
- d. Setting: runback, trip, communication failure, SCADA etc. **(RAS Owner)**
- e. RAS arming **(RAS Owner)**
- f. RAS enable/disable alarms **(RAS Owner)**
- g. Redundancy features **(RAS Owner)**
- h. Monitoring **(RAS Owner)**
- i. Procedure when RAS not available **(ISO)**
- j. Telecommunication path details **(RAS Owner)**
- k. Commissioning, Maintenance and Testing **(RAS Owner)**
- l. Performance and Operational history **(RAS Owner)**

Appendix 1 – RAS Data and Documentation Form

ISO

Data

Name	Brief description	In Service Date	Function	Impact	Group Number	Group Name	Type	Trigger Event	Reason	Status	Project that will allow removal	Estimated Year of Removal

List of Documents

- a. Procedure when RAS not available

RAS Owner

Data

Location	Ownership

List of Documents

- a. Diagram indicating multiple ownership and boundaries
- b. High level logic diagram showing the inputs, logic and trips
- c. RAS Logic Hardware
- d. Setting: runback, trip, communication failure, SCADA etc.
- e. RAS Arming
- f. RAS enable/disable alarms
- g. Redundancy features
- h. Monitoring
- i. Telecommunication path details
- j. Commissioning, Maintenance and Testing
- k. Performance and Operational history

ARC Technical Work Group Assessment and Conversion of NERC PRC-005-1 to Alberta PRC-005-AB-1 Transmission and Generation Protection System Maintenance and Testing			
Section	NERC PRC-005-1	Alberta PRC-005-AB-1	Reason for Difference ⁸
Purpose	To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.	<u>The purpose of this reliability standard is to ensure all transmission and generation protection systems affecting the reliability of the Bulk Electric System-BES are maintained and tested.</u>	
Applicability	<p>4.1. Transmission Owner.</p> <p>4.2. Generator Owner.</p> <p>4.3. Distribution Provider that owns a transmission Protection System.</p>	<p><u>This reliability standard applies to:</u></p> <ul style="list-style-type: none"> - 4.1. Transmission Owner TFOs - <u>GFOs with protection systems that directly affect the reliability of the BES. These protection systems include all those that measure voltage, current, or frequency from the generating unit to the AIES, but exclude the prime mover and associated control systems.</u> 4.2. Generator Owner. 4.3. Distribution Provider that owns a transmission Protection System. 	Moved description of protection systems applicable to GFOs to the applicability section.
Effective Date	May 1, 2006	<u>180 calendar days after the date of approval by the Commission.</u>	<p>180 days required to complete documentation of maintenance and testing programs.</p> <p>NOTE: NERC PRC-005-2 is presently under development by NERC. The present proposal substantially changes all requirements and will be reviewed for applicability in Alberta once approved by the NERC BOT.</p>
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta	Added definitions section to the Alberta reliability standard.

⁸ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

**ARC Technical Work Group Assessment and Conversion of NERC PRC-005-1 to Alberta PRC-005-AB-1
Transmission and Generation Protection System Maintenance and Testing**

Section	NERC PRC-005-1	Alberta PRC-005-AB-1	Reason for Difference ⁸
		Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ⁹	
Requirement	R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:	<p>R1 Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System TFOs and GFOs must each shall have a Protection protection system-system maintenance and testing program for Protection-protection Systems systems that directly affects the reliability of the BES.</p> <p>protection systems that directly affect the reliability of the BES these Each The program shall must include the following:</p>	
Measure			Measures included in sub-requirements.
Requirement	R1.1. Maintenance and testing intervals and their basis.	R1.1 Documented rationale for the intervals chosen for maintenance and testing intervals and their basis.	
Measure		MR1.1 Documents must exist as specified in requirement R1.1.	
Requirement	R1.2. Summary of maintenance and testing procedures.	R1.2 Summary of Documented maintenance and testing procedures.	

⁹ Defined terms are not italicized in this document, but will appear in the Alberta Reliability Standards document.

**ARC Technical Work Group Assessment and Conversion of NERC PRC-005-1 to Alberta PRC-005-AB-1
Transmission and Generation Protection System Maintenance and Testing**

Section	NERC PRC-005-1	Alberta PRC-005-AB-1	Reason for Difference ⁸
Measure	M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.	M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated protection system maintenance and testing program as defined in Requirement 1. MR1.2 Documents must exist as specified in requirement R1.2.	
Requirement	R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:	R2 Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System TFOs and GFOs shall must each provide documentation of its protection system maintenance and testing program and the implementation of that program to its Regional Reliability Organization the ISO on request and not later than (within 30 calendar days of such request) . The program implementation documentation of the program implementation shall must include evidence that protection system devices were maintained and tested within the maintenance and testing intervals as referenced in requirement R1.1.;	
Measure		MR2 Evidence that the program was submitted as specified in requirement R2.	
Requirement	R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.	R2.1. Evidence Protection System devices were maintained and tested within the defined intervals. R3 Each TFO and GFO must, as of the effective date of this reliability standard, implement its protection system maintenance and testing the program and test protection devices in accordance with their program.	Added that implementation of the maintenance and testing program starts as of the effective date of this reliability standard.

**ARC Technical Work Group Assessment and Conversion of NERC PRC-005-1 to Alberta PRC-005-AB-1
Transmission and Generation Protection System Maintenance and Testing**

Section	NERC PRC-005-1	Alberta PRC-005-AB-1	Reason for Difference ⁸
Measure	M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.	M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence that it provided documentation of its associated protection system maintenance and testing program and the implementation of its program as defined in Requirement 2. MR32 Evidence that the relays were tested as specified in requirement R3.	
Procedures	None identified	None identified	
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/PRC-005-1.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.
Regional Differences	None identified	None identified	Not applicable in Alberta

Proposed Terms for the ARS Glossary:

None

Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

- *Alberta Interconnected Electric System (AIES)*
- *bulk electric system or BES*
- *day*
- *generation facility owner or GFO*
- *Independent System Operator or ISO*
- *protection system*
- *reliability standard*
- *transmission facility owner or TFO*

2010-04-30

Status of PRC Standards

Standard	Title	Status
PRC-011-AB-0	UVLS System Maintenance and Testing	Re-submitted to ARC.
PRC-017-AB-0	Remedial Action Scheme Maintenance and Testing	Re-submitted to ARC.
PRC-005-AB-1	Transmission and Generation Protection System Maintenance and Testing	Draft 3 revised to align with other PRC maintenance and testing standards. This standard was ready to be recommended for filing with the AUC.
PRC-015-AB-0	Remedial Action Scheme Data and Documentation	Next step is to prepare for stakeholder consultation.
PRC-016-AB-0	Remedial Action Scheme Misoperations	Next step is to request approval to file with the AUC.
PRC-018-AB-1	Disturbance Monitoring Equipment Installation and Data Reporting	Next step is to prepare for stakeholder consultation.
PRC-023-AB-1	Transmission Relay Loadability	Next step is to prepare for stakeholder consultation.

ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1 Telecommunications				
Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
Purpose	Each Reliability Coordinator, Transmission Operator and Balancing Authority needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.	<u>The purpose of this reliability standard is to ensure the ISO and TFOs have Each Reliability Coordinator, Transmission Operator and Balancing Authority</u> needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.		
Applicability	4.1. Transmission Operators. 4.2. Balancing Authorities. 4.3. Reliability Coordinators. 4.4. NERCNet User Organizations.	<u>This reliability standard applies to:</u> • ISO • TFOs 4.1. Transmission Operators. 4.2. Balancing Authorities. 4.3. Reliability Coordinators. 4.4. NERCNet User Organizations		
Effective Date	May 13, 2009	Ninety <u>calendar days after the date of approval by the Commission.</u>		

¹⁰ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as "shall" to "must".
- Developed measures specific to the requirements.

¹¹ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
Definitions		<p><u>May 13, 2009</u></p> <p>Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.¹²</p>	Added definitions section to the Alberta reliability standard.	
Requirement	<p>R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:</p>	<p>R1 The ISO must Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate, and reliable, and where applicable, diverse and redundant telecommunications facilities, for the exchange of Interconnection and operating information internally and with for the following:</p> <p><u>within their respective organization, the ISO</u></p> <ul style="list-style-type: none"> • <u>with other TFOs</u> • <u>with other interconnected transmission operators, and balancing authorities as necessary to maintain reliability</u> • <u>with the WECC Reliability Coordinator</u> <p><u>with respect to TFOs, with the ISO.</u></p>	<p>NERC requirement R1 was split into two Alberta requirements, R1 for the ISO and R2 for the TFOs.</p> <p>Moved the NERC sub-requirements for R1 into the main Alberta requirements - R1 and R2.</p>	RO – Bill Baker

¹² Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.

**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
		<u>with respect to the IS</u>		
Measure		MR1 Evidence exists and shows of adequate and reliable telecommunications <u>exists, such as a description of facilities or a diagram identifying the communications,</u> as specified in requirement R1.		
Requirement	R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information:	R2 Each The -TFOs must each provide adequate, reliable, and where applicable, diverse and redundant telecommunications facilities the, for the exchange of Interconnection and operating information <u>internally and with</u> for <u>the following:</u> <ul style="list-style-type: none"> • within their respective organization • with other TFOs • with other interconnected tTransmission oOperators. • with the ISO 	NERC requirement R1 was split into two requirements, R1 for the ISO and R2 for the TFOs. Moved the NERC sub-requirements for R1 into the main Alberta requirements - R1 and R2.	
Measure		MR12 Evidence of exists and shows adequate and reliable telecommunications exists, <u>exists, such as a description of facilities or a diagram identifying the communications, as specified in requirement R2.</u>		Provided examples of what evidence may include, same as MR1 for the similar ISO requirement.

**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
Requirement	R1.1. Internally.	R1.1. Internally.	Included as bullet point in R1 and R2.	
Measure				
Requirement	R1.2. Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	R1.2. Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	Included as bullet point in R1 and R2.	
Measure				
Requirement	R1.3. With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	R1.3. With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	Included as bullet point in R1 & R2.	
Measure				
Requirement	R1.4. Where applicable, these facilities shall be redundant and diversely routed.	R1.4. Where applicable, these facilities shall be redundant and diversely routed.	Included in R1 & R2.	
Measure				
Requirement	R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	R2³ <u>The ISO and each TFOs must</u> each Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities, <u>including without limitation,</u> Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	Removed the emphasis on 'special attention' as it is not measurable. Combined the two sentences in the NERC requirement into a single sentence.	RO – Bill Baker (voice) RO- Neil Curtis (data) (possibly Jack Kelly)

**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
Measure	<p>M1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include, but is not limited to communication facility test-procedure documents, records of testing, and maintenance records for communication facilities or equivalent that will be used to confirm that it manages, alarms, tests and/or actively monitors vital telecommunications facilities. (Requirement 2 part 1)</p>	<p>MR3 <u>Evidence exists to confirm the ISO and TFO each manages,</u> alarms, tests and/or actively monitors <u>vital telecommunications facilities as specified in accordance within requirement R23.</u> <u>Documentation exists that include, but is not limited to, of</u> <u>communication facility test-procedure documents, records of testing, and maintenance records for telecommunication facilities or equivalent.</u> <u>exists</u></p>		
Requirement	<p>R3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.</p>	<p>R34 <u>The ISO and each TFOs each must Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a</u> <u>means to</u> coordinate telecommunications, <u>among their respective areas, including without limitation, coordinating with the WECC Reliability Coordinator and adjacent transmission operators and balancing authorities.</u> <u>-This coordination shall include the the</u> ability to investigate and recommend solutions to telecommunications problems within <u>the area Alberta, and with the</u></p>		<p>RO – Bill Baker (voice) RO- Neil Curtis (data) (possibly Jack Kelly)</p>

**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
		WECC Reliability Coordinator and adjacent interconnected transmission operators and balancing authorities other areas.		
Measure		MR4 Evidence exists, such as Email, and phonelog files, voice recordings or other equivalent evidence, exist and show to confirm the ISO and TFOs coordinated telecommunications among respective areas as specified in requirement requirement R34.		
Requirement	R4. Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.	R45 The ISO and each TFOs each must Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use the English as the language for all communications between their respective and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.		RO – Neil Curtis

**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
Measure	<p>M2. The Reliability Coordinator, Transmission Operator or Balancing Authority shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent, that will be used to determine compliance to Requirement 4.</p>	<p>MR52 Evidence exists that include, <u>but is not limited to,</u> such as <u>operator logs, email, voice recordings or e-tag documents, to confirm the ISO or and/or TFOs</u> voice records exists and shows that English is used <u>English language is used for all communications</u> The Reliability Coordinator, Transmission Operator or Balancing Authority shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent, that will be used to determine compliance to Requirement 4 <u>as specified in requirement R5.</u></p>		
Requirement	<p>R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.</p>	<p>R56 <u>The ISO and each TFOs must</u> each Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.</p>		RO – Doug Hincks

**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
Measure	M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request its current operating instructions and procedures, either electronic or hard copy that will be used to confirm that it meets Requirement 5.	MR563 Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request its <u>Written operating instructions and procedures exist as specified in accordance with requirement</u> Evidence exists and shows current operating instructions and procedures are either electronic or hard copy that will be used to confirm that it meets Requirement <u>R56.</u>		
Requirement	R6. Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001, "NERCNet Security Policy."	R6. Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001, "NERCNet Security Policy."	Alberta Variance¹³: The NERC requirement for NERCNet User organizations to adhere to Attachment 1-COM-001, "NERCNet Security Policy" was deleted as no Alberta entity is a NERCNet User Organization.	

¹³ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference ¹⁰	Comments ¹¹
Measure	<p>M4. The NERCnet User Organization shall have and provide upon request evidence that could include, but is not limited to documented procedures, operator logs, voice recordings or transcripts of voice recordings, electronic communications, etc that will be used to determine if it adhered to the (User Accountability and Compliance) requirements in Attachment 1-COM-001. (Requirement 6)</p>	<p>M4. The NERCnet User Organization shall have and provide upon request evidence that could include, but is not limited to documented procedures, operator logs, voice recordings or transcripts of voice recordings, electronic communications, etc that will be used to determine if it adhered to the (User Accountability and Compliance) requirements in Attachment 1-COM-001. (Requirement 6)</p>		
Procedures				
Compliance	<p>To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/COM-001-1_1.pdf</p>		<p>There is no compliance section currently proposed in the Alberta Reliability Standards.</p> <p>A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta.</p> <p>This approach is deemed consistent with the existing ISO Rules.</p>	



**ARC Operations Work Group Assessment and Conversion of NERC COM-001-1.1 to Alberta COM-001-AB-1.1
Telecommunications**

Section	NERC COM-001-1.1	Alberta COM-001-AB-1.1	Reason for Difference¹⁰	Comments¹¹
Regional Differences	None identified.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

- balancing authorities
- bulk electric system (BES)
- Commission
- days
- Interconnection
- ISO
- reliability
- reliability standard
- transmission facility owner (TFO)
- transmission operators
- WECC

Standard Owner:

Neil Curtis, Director - Grid and Market Operations



AESO Requirement Owner(s):

Bill Baker, Director - IT Operations & Support for requirement R1, R3 (for the voice component), R4 (for the voice component).

Don Adair, Technical Specialist for requirement R4 (for the system planning component).

Neil Curtis, Director - Grid and Market Operations for requirement R3 (with Jack Kelly for the data component), R4 (with Jack Kelly for the data component) and R5.

Doug Hincks, Director - Operations Support for requirement R6.

AESO Subject Matter Expert(s):

Don Adair, Technical Specialist

Bill Baker, Director - IT Operations & Support

Dan Shield, Technical Specialist for technical standards as SME for R2.

Work Group Comments:

Consider adding reference to the applicable ISO standards (operational and voice) for R2.

ISO Response:

The existing AESO standards do not cover all aspects of requirement R2 and as such it is not appropriate to directly reference the AESO standards in the requirement.

Work Group Recommendation:

OWG members recommend this reliability standard to the ARC members.

Developed by:



Name	Organization	Role
Jerry Mossing	AESO	OWG member
Ken Gardner	AESO	Reliability Standards Specialist
Doug Hincks	AESO	OWG Chair
Neil Curtis	AESO	OWG Alternate Chair and Standard Owner
Bill Baker	AESO	Subject matter expert
Nancy Cameron	AESO	Measures Development
Elizabeth Olivier	Consultant	Technical Writer Review
Anirban Bosu	TransAlta	OWG member
Ron Smith	AESO	OWG member
Mark Thompson	AESO	OWG member
Peter Tam	AESO	OWG member
Elizabeth Olivier	Consultant	Technical writer review
Larry Kram	AESO	Legal review
John Walker	ATCO Power	OWG member
Rick Spyker	Altalink	OWG member
Blaine Beisiegel	ATCO Electric	OWG member
Subrota Bairagi	Suncor	OWG member
Roy Hanson	ENMAX	OWG member
Ravinder Farwaha	Suncor	OWG member
Gerry Young	Suncor	OWG member
Chris Best	TransCanada	OWG member
Terri Haffick	ENMAX	OWG member
Kevin Neithercut	ENMAX	OWG member
Dan Bamber	TransAlta	OWG member



Name	Organization	Role
Dwayne Aasberg	Dow Chemical	OWG member
Amber Kirby	Capital Power	OWG member
Michael Taylor	Capital Power Corp.	OWG member
Stew Purkis	City of Lethbridge	OWG member
Cal Lenz	ATCO Power	OWG member
Blaise Smith	TransAlta	OWG member
Penny Haldane	ENMAX	OWG member

Attachment 1 that follows does not apply in Alberta and will not be included in the Alberta reliability standard ...

Attachment 1-COM-001— NERCnet Security Policy

Policy Statement

The purpose of this NERCnet Security Policy is to establish responsibilities and minimum requirements for the protection of information assets, computer systems and facilities of NERC and other users of the NERC frame relay network known as "NERCnet." The goal of this policy is to prevent misuse and loss of assets.

For the purpose of this document, information assets shall be defined as processed or unprocessed data using the NERCnet Telecommunications Facilities including network documentation. This policy shall also apply as appropriate to employees and agents of other corporations or organizations that may be directly or indirectly granted access to information associated with NERCnet.

The objectives of the NERCnet Security Policy are:

- To ensure that NERCnet information assets are adequately protected on a cost-effective basis and to a level that allows NERC to fulfill its mission.
- To establish connectivity guidelines for a minimum level of security for the network.
- To provide a mandate to all Users of NERCnet to properly handle and protect the information that they have access to in order for NERC to be able to properly conduct its business and provide services to its customers.

NERC's Security Mission Statement

NERC recognizes its dependency on data, information, and the computer systems used to facilitate effective operation of its business and fulfillment of its mission. NERC also recognizes the value of the information maintained and provided to its members and others authorized to have access to NERCnet. It is, therefore, essential that this data, information, and computer systems, and the manual and technical infrastructure that supports it, are secure from destruction, corruption, unauthorized access, and accidental or deliberate breach of confidentiality.

Implementation and Responsibilities

This section identifies the various roles and responsibilities related to the protection of NERCnet resources.

NERCnet User Organizations

Users of NERCnet who have received authorization from NERC to access the NERC network are considered users of NERCnet resources. To be granted access, users shall complete a User Application Form and submit this form to the NERC Telecommunications Manager.

Responsibilities

It is the responsibility of NERCnet User Organizations to:

- Use NERCnet facilities for NERC-authorized business purposes only.
- Comply with the NERCnet security policies, standards, and guidelines, as well as any procedures specified by the data owner.

- Prevent unauthorized disclosure of the data.
- Report security exposures, misuse, or non-compliance situations via Reliability Coordinator Information System or the NERC Telecommunications Manager.
- Protect the confidentiality of all user IDs and passwords.
- Maintain the data they own.
- Maintain documentation identifying the users who are granted access to NERCnet data or applications.
- Authorize users within their organizations to access NERCnet data and applications.
- Advise staff on NERCnet Security Policy.
- Ensure that all NERCnet users understand their obligation to protect these assets.
- Conduct self-assessments for compliance.

User Accountability and Compliance

All users of NERCnet shall be familiar and ensure compliance with the policies in this document.

Violations of the NERCnet Security Policy shall include, but not be limited to any act that:

- Exposes NERC or any user of NERCnet to actual or potential monetary loss through the compromise of data security or damage.
- Involves the disclosure of trade secrets, intellectual property, confidential information or the unauthorized use of data.

Involves the use of data for illicit purposes, which may include violation of any law, regulation or reporting requirement of any law enforcement or government body.

ARC Operation Work Group Assessment and Conversion of NERC COM-002-2 to Alberta COM-002-AB-2				
Communications and Coordination				
Section	NERC COM-002-2	Alberta COM-002-AB-2	Reason for Difference ¹⁴	Comments ¹⁵
Purpose	To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.	<u>The purpose of this reliability standard is to ensure the ISO, TFOs, GFOs and operators of generating units</u> operators, Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications and response capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.		
Applicability	4.1. Reliability Coordinators. 4.2. Balancing Authorities. 4.3. Transmission Operators. 4.4. Generator Operators.	<u>This reliability standard applies to:</u> 4.1. Reliability Coordinators. 4.2. Balancing Authorities. 4.3. Transmission Operators. • 4.4. Generator Operators. <u>ISO</u> • <u>TFOs</u> • <u>GFOs</u> • <u>operators of generating facilities</u> <u>units</u>		

¹⁴ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

¹⁵ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operation Work Group Assessment and Conversion of NERC COM-002-2 to Alberta COM-002-AB-2
Communications and Coordination**

Section	NERC COM-002-2	Alberta COM-002-AB-2	Reason for Difference ¹⁴	Comments ¹⁵
Effective Date	January 1, 2007	<u>Ninety calendar days after the date of approval by the Commission, January 1, 2007</u>		
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ¹⁶	Added definitions section to the Alberta reliability standard.	
Requirement	R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.	R1 Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications-voice and data communication links, with the ISO and appropriate Reliability Coordinators, TFOs, appropriate units, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition. <u>R2 The ISO, each TFOs, and each operators of a generating units each must be staffed and available, when it receives a communication, to address a real-time emergency.</u>	TFO and ISO requirements have been covered in COM-001.	RO for R2 – Neil Curtis

¹⁶ Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.

**ARC Operation Work Group Assessment and Conversion of NERC COM-002-2 to Alberta COM-002-AB-2
Communications and Coordination**

Section	NERC COM-002-2	Alberta COM-002-AB-2	Reason for Difference ¹⁴	Comments ¹⁵
		<p>condition respond to Such communications shall be staffed and available for addressing a real-time emergency condition requests, including without limitation, a real-time emergency condition.</p>		
Measure	<p>M1. Each Transmission Operator, Balancing Authority and Generator Operator shall have communication facilities (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators and shall have and provide as evidence, a list of communication facilities or other equivalent evidence that confirms that the communications have been provided to address a real-time emergency condition. (Requirement 1, part 1)</p>	<p>MR1 Voice and data communications facilities exist and meet the ISO Rules requirements. A list of communication facilities or other equivalent evidence that confirms that voice and communication facilities exist as specified in requirement R1.</p> <p>MR2.</p> <p>MR32. <u>Where a real-time emergency condition has occurred evidence exists that include, but is not limited to, such as voice recordings and or operator logs which that demonstrate communication requests were addressed.</u></p> <p>Each Transmission Operator, Balancing Authority and Generator Operator shall have communication facilities (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and</p>		<p>Modified the measure and the reference to ISO rules was removed from the measure as it does do not cover all aspects of requirement R1.</p>

**ARC Operation Work Group Assessment and Conversion of NERC COM-002-2 to Alberta COM-002-AB-2
Communications and Coordination**

Section	NERC COM-002-2	Alberta COM-002-AB-2	Reason for Difference ¹⁴	Comments ¹⁵
		<p>Transmission Operators and shall have and provide as evidence, a list of communication facilities or other equivalent evidence that confirms that the communications have been provided to address a real-time emergency condition. (Requirement 1, part 1)</p>		
Requirement	<p>R1.1. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.</p>	<p>R31.1. <u>The ISO must notify the WECC Reliability Coordinator and adjacent interconnected Transmission Operators and affected adjacent Balancing Authorities,</u> through predetermined communication paths. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area the AIES, or when if the ISO anticipates shedding firm load shedding is anticipated.</p>		RO - Neil Curtis

**ARC Operation Work Group Assessment and Conversion of NERC COM-002-2 to Alberta COM-002-AB-2
Communications and Coordination**

Section	NERC COM-002-2	Alberta COM-002-AB-2	Reason for Difference ¹⁴	Comments ¹⁵
Measure		<u>MR43 Evidence exists that include, but is not limited to, such as Vvoice recordings, operator logs and, or email records exist to confirm notification as specified in requirement R3. and show WECC Reliability Coordinator and adjacent interconnected transmission operators Transmission Operators and affected adjacent Balancing Authorities were notified.</u>		
Requirement	R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.	<u>R42 Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue The ISO must give aissue verbal directives in a clear, concise, and definitive manner. When Tthe ISO must request the If the recipient of the verbal directive tdoes not respond by repeating the information in the directive as provided for in requirement R5, then the ISO must request the recipient to repeat the information in the directive. If the information is repeated correctly the ISO must receives a response to a directive it musacknowledge this to</u>	Alberta Variance¹⁷: The ISO recognizes the responsibility to respond to the directive rests with the recipient of the directive. A new requirement, R5, was added to the Alberta reliability standard to address this.	RO – Neil Curtis

¹⁷ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

**ARC Operation Work Group Assessment and Conversion of NERC COM-002-2 to Alberta COM-002-AB-2
Communications and Coordination**

Section	NERC COM-002-2	Alberta COM-002-AB-2	Reason for Difference ¹⁴	Comments ¹⁵
		<p>the recipient. † If –shall ensure the recipient of the directive repeats the information back correct and, shall acknowledge the response as correct or the information in the response is not correct, the ISO must repeating the verbal original statement directive and the above process until it is satisfied that the recipient understands the information in the directive. to resolve any misunderstandings.</p>		
Measure	<p>M2. The Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators of a condition that could threaten the reliability of its area or when firm load shedding was anticipated. (Requirement 1.1)</p>	<p>MR452 <u>Voice records exist and meet the requirement directives as specified in requirement R54.</u> were met The Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators of a</p>		

**ARC Operation Work Group Assessment and Conversion of NERC COM-002-2 to Alberta COM-002-AB-2
Communications and Coordination**

Section	NERC COM-002-2	Alberta COM-002-AB-2	Reason for Difference ¹⁴	Comments ¹⁵
<u>Requirement</u>		<u>R65 The Each TFOs, and operators of a generating units whothat who receives a verbal directive must repeat the information in the verbal directive back to the ISO correctly, either in response to the initial verbal directive or in response to the ISO's repetition of the verbal directive. any corrected statement to resolve any misunderstandings.</u>		
<u>Measure</u>		<u>MR65 Evidence exists that include, but is not limited to, such as voice recordings, operator logs and ,eemail records exist andto verify demonstrate the requirement as specified in requirement in R65 were met.</u>		
Procedures				
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/COM-002-2.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring	

**ARC Operation Work Group Assessment and Conversion of NERC COM-002-2 to Alberta COM-002-AB-2
Communications and Coordination**

Section	NERC COM-002-2	Alberta COM-002-AB-2	Reason for Difference¹⁴	Comments¹⁵
			and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	None identified.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

- adjacent balancing authorities
- Commission
- days
- generating facility owner
- interconnected transmission operators
- ISO
- load shed
- reliability
- reliability standard



- transmission facility owner (TFO)
- WECC

Standard Owner:

Neil Curtis, Director - Grid and Market Operations

AESO Requirement Owner(s):

Neil Curtis, Director - Grid and Market Operations for requirement R2, R4 and R5.

AESO Subject Matter Expert(s):

Don Adair, Manager, Special Projects

Work Group Comments:

1. Capital Power and other OWG members would like to have RSAWs made available prior to implementing the standard. 2010-02-01.
2. Recommend revising the registry for GOP/operator of a generating unit.
3. Recommend reviewing the need for a definition for “operator of a generating unit” with the TOAD project.
4. ENMAX, TransAlta, DOW and Capital Power would like more lead time for producing evidence and training, recommend 6 months after approval by the Commission for all reliability standards.

ISO Response:

The following are the responses from the ISO on the above items:

1. As the RSAW for this reliability standard is developed it will be made public to stakeholders. An RSAW is developed once the standard is approved. The AESO will make the RSAW available publicly for information purposes. We are targeting to have new RSAWs completed within 60 days of a standard being approved and becoming effective. An RSAW is a document or worksheet used by the compliance monitor to assess compliance to a *reliability standard*. The tool is intended to support consistent and efficient assessments of each standard. It re-states the requirements and associated measures of that standard; provides a description of the approach; and a template for documenting finding, evidence and notes. An RSAW does not set new requirements for compliance. Entities are not required to comply with RSAWs, but are required to comply with the approved standard and the requirements of the standard.



2. This request will be addressed by the ISO compliance group.
3. The term “operator” is currently being addressed and will be consulted on as part of the TOAD project and the term “generating unit” is a defined term in the ISO rules glossary.
4. The effective date for this reliability standard has been changed from 30 to 90 calendar days after approval by the Commission. The request for additional lead time beyond 90 calendar days can be discussed at the ARC meeting.

Work Group Recommendation:

OWG members support the recommendation to submit this reliability standard to the ARC and will review ISO responses and proposed revisions when the ISO sends the standard to the ARC members.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	OWG member
Ken Gardner	AESO	Reliability Standards Specialist
Anirban Bosu	TransAlta	OWG member
Neil Curtis	AESO	OWG Alternate Chair and Standard Owner
Doug Hincks	AESO	OWG Chair
Nancy Cameron	AESO	Measures Development
Ron Smith	AESO	OWG member
Mark Thompson	AESO	OWG member
Peter Tam	AESO	OWG member
Elizabeth Olivier	AESO	Technical Writer review
Larry Kram	AESO	Legal review
John Walker	ATCO Power	OWG member
Rick Spyker	Altalink	OWG member



Name	Organization	Role
Blaine Beisiegel	ATCO Electric	OWG member
Subrota Bairagi	Suncor	OWG member
Roy Hanson	ENMAX	OWG member
Ravinder Farwaha	Suncor	OWG member
Gerry Young	Suncor	OWG member
Chris Best	TransCanada	OWG member
Terri Haffick	ENMAX	OWG member
Kevin Neithercut	ENMAX	OWG member
Dan Bamber	TransAlta	OWG member
Dwayne Aasberg	Dow Chemical	OWG member
Amber Kirby	Capital Power Corp.	OWG member
Michael Taylor	Capital Power Corp.	OWG member
Stew Purkis	City of Lethbridge	OWG member
Cal Lenz	ATCO Power	OWG member
Blaise Smith	TransAlta	OWG member
Penny Haldane	ENMAX	OWG member

ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3				
Reliability Coordination Current Day Operations				
Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
Purpose	The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.	<p><u>The purpose of this reliability standard is to ensure the WECC RC is notified of RAS failures and the lowest system operating limits are used between the AIES and adjacent balancing authority areas.</u></p> <p>The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.</p>	Developed a purpose that is aligned with the requirements in the proposed Alberta reliability standard.	
Applicability	<p>4.1. Reliability Coordinators.</p> <p>4.2. Balancing Authorities.</p> <p>4.3. Transmission Operators.</p> <p>4.4. Transmission Service Providers.</p> <p>4.5. Generator Operators.</p> <p>4.6. Load-Serving Entities.</p>	<p><u>This reliability standard applies to:</u></p> <ul style="list-style-type: none"> • <u>ISO</u> • <u>TFOs</u> • <u>GFOs</u> • <u>Operators of generating units</u> 		

¹⁸ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

¹⁹ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	4.7. Purchasing-Selling Entities.	4.1. Reliability Coordinators. 4.2. Balancing Authorities. 4.3. Transmission Operators. 4.4. Transmission Service Providers. 4.5. Generator Operators 4.6. Load-Serving Entities. 4.7. Purchasing-Selling Entities		
Effective Date	<p>In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.</p> <p>In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.</p>	<p><u>Ninety calendar days after the date of approval by the Commission.</u>In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption. In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.</p>		
Definitions		Italicized terms used in this	Added definitions	

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference¹⁸	Comments¹⁹
		reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ²⁰	section to the Alberta reliability standard.	
Requirement	R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:	R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:	This requirement and its sub-requirements apply to Reliability Coordinators.	
Measure				
Requirement	R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.		
Measure				
Requirement	R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.		

²⁰ Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference¹⁸	Comments¹⁹
Measure				
Requirement	R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.		
Measure				
Requirement	R1.4. System real and reactive reserves (actual versus required).	R1.4. System real and reactive reserves (actual versus required).		
Measure				
Requirement	R1.5. Capacity and energy adequacy conditions.	R1.5. Capacity and energy adequacy conditions.		
Measure				
Requirement	R1.6. Current ACE for all its Balancing Authorities.	R1.6. Current ACE for all its Balancing Authorities.		
Measure				
Requirement	R1.7. Current local or Transmission Loading Relief procedures in effect.	R1.7. Current local or Transmission Loading Relief procedures in effect.		
Measure				
Requirement	R1.8. Planned generation dispatches.	R1.8. Planned generation dispatches.		
Measure				
Requirement	R1.9. Planned transmission or generation outages.	R1.9. Planned transmission or generation outages.		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
Measure	M1. The Reliability Coordinator shall have and provide upon request 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 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.	M1. The Reliability Coordinator shall have and provide upon request 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 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.		
Requirement	R1.10. Contingency events.	R1.10. Contingency events.		
Measure				
Requirement	R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters 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	R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters 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.	This requirement applies to Reliability Coordinators.	

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	<p>Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.</p>	<p>If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.</p>		
Measure	<p>M2. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request 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 Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities.</p>	<p>M2. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request 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 Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring</p>		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	(Requirement 2 and Requirement 7)	Balancing Authorities. (Requirement 2 and Requirement 7)		
Requirement	R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	This requirement applies to Reliability Coordinators.	
Measure	M3. The Reliability Coordinator shall have and provide upon request 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 determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)	M3. The Reliability Coordinator shall have and provide upon request 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 determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
Requirement	R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.	R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.		
Measure	M4. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.	M4. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.		
Requirement	R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its	R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed	Alberta Variance²¹: IRO-001-AB-1 R1 covers all WECC Reliability Coordinator directives to the ISO.	

²¹ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	Reliability Coordinator to relieve the emergent condition.	by its Reliability Coordinator to relieve the emergent condition.		
Measure	<p>M5. The Reliability Coordinator shall have and provide upon request 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 Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.</p> <p>M6. The Transmission Operators and Balancing Authorities shall have and provide upon request 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 firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent</p>	<p>M5. The Reliability Coordinator shall have and provide upon request 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 Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.</p> <p>M6. The Transmission Operators and Balancing Authorities shall have and provide upon request 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 firm load</p>		

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Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	condition. (Requirement 5 Part 2)	shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)		
Requirement	R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	This requirement applies to Reliability Coordinators.	
Measure	M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or	M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	<p>equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)</p>	<p>or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)</p>		
Requirement	<p>R7. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.</p>	<p>R7. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.</p>	<p>This requirement applies to Reliability Coordinators.</p>	
Measure	<p>M2. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could</p>	<p>M2. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request</p>		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference¹⁸	Comments¹⁹
	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 Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)	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 Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)		
Requirement	R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	This requirement applies to Reliability Coordinators.	

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Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
Measure	M8. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)	M8. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)		
Requirement	R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the	<u>R1. Each TFO, GFO and operator of a generating unit must notify the ISO, as soon as practical, of any status change of any remedial action scheme that impacts the AIES and adjacent balancing authority area(s), status change that results in, or may result in, -thee</u>	The first sentence of the requirement applies to Reliability Coordinators. Alberta Variance²²: NERC requirement R9 states that degradation of RAS is to be reported to the reliability	

²² An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

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Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	<p>operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.</p>	<p>potential failure or failure of the remedial action scheme to operate as designed impact AES and adjacent balancing authority area(s).</p> <p>R92. <u>Subject to notification under requirement R1 Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately</u> <u>ISO must inform notify the Reliability Coordinator WECC Reliability Coordinator of such status change of the status of the Special Protection System remedial action scheme including any degradation or</u></p>	<p>coordinator, however it is the opinion of the ISO that degradation is not measurable. It is reasonable to notify the reliability coordinator of a RAS status change that results in the failure of a RAS to operate as designed.</p>	

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Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
		<p>potential failure remedial action scheme to operate as expected that has an impact between Bbalancing Aauthority areas (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation).</p>		
Measure	<p>M9. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, 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 Special Protection System on inter-area flows. (Requirement 9)</p>	<p><u>MR1. Evidence such as voice recordings, electronic communications or other equivalent evidence exists to show that the ISO was informed as specified in requirement R1.</u></p> <p><u>MR2. Evidence such as voice recordings, electronic communications or other equivalent evidence exists to show that the WECC Reliability Coordinator was informed as specified in requirement R2.</u></p> <p>M9 If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence</p>		

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Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
		<p>that could include, but is not limited to, agreements with their Transmission Operators, 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 Special Protection System on inter-area flows. (Requirement 9)</p>		
Requirement	<p>R10. In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.</p>	<p>R10R3. In instances wln the event therehere there is a difference in <u>system operating limits betweenon an interconnection between the AIES and adjacent balancing authority area(s) derived limits,</u> the <u>Transmission Operators SO,</u> <u>each TFO and operators of a generating units.</u> Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities <u>mustshall</u> always operate <u>the AIES to the lowest of such system operating limits.</u> Bulk</p>		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
Measure	<p>M10. If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request 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 to the most limiting parameter. (Part 2 of Requirement 10)</p>	<p>Electric System to the most limiting parameter.</p> <p><u>MR3. Evidence such as a record of voice recordings, electronic communications, operator logs, or other equivalent evidence exists to show that the ISO operated to the lowest system operating limit as specified in requirement R3.</u></p> <p>M10 If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request 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 to the most limiting parameter. (Part 2 of Requirement 10)</p>		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference¹⁸	Comments¹⁹
Requirement	<p>R11. The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.</p>	<p>R11. The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.</p>	<p>Alberta Variance²³ – NERC requirement R11 implies separate entities for Transmission Service Provider and the entity that establishes SOLs and IROLs. The ISO is both the transmission service provider and the applicable entity for calculating ATC and TTC in Alberta, therefore this requirement is redundant and not required to be included in the Alberta reliability standard.</p>	

²³ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
Measure	M11. The Transmission Service Providers shall have and provide upon request 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 SOLs or IROs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11 Part 2)	M11. The Transmission Service Providers shall have and provide upon request 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 SOLs or IROs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11 Part 2)		
Requirement	R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this	R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall	This requirement applies to Reliability Coordinators.	

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Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	<p>information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.</p>	<p>disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.</p>		
Measure	<p>M12. The Reliability Coordinator shall have and provide upon request 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 issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1. M13. The Reliability Coordinator</p>	<p>M12. The Reliability Coordinator shall have and provide upon request 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 issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in</p>		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference ¹⁸	Comments ¹⁹
	<p>shall have and provide upon request 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 upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.</p> <p>M14. The Reliability Coordinator shall have and provide upon request 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 notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)</p>	<p>Requirement 12 Part 1.</p> <p>M13. The Reliability Coordinator shall have and provide upon request 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 upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.</p> <p>M14. The Reliability Coordinator shall have and provide upon request 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 notified all</p>		

**ARC Operations Work Group Assessment and Conversion of NERC IRO-005-3 to Alberta IRO-005-AB-3
Reliability Coordination Current Day Operations**

Section	NERC IRO-005-3	Alberta IRO-005-AB-3	Reason for Difference¹⁸	Comments¹⁹
		impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)		
Procedures Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/IRO-005-3.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	None identified.		Not applicable in Alberta	



Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

balancing authority

Commission

day

interconnected transmission operator

interconnection reliability operating limit (IROL)

ISO

generating facility owner (GFO)

reliability

reliability standard

remedial action scheme (RAS)

system operating limit (SOL)

transmission facility owner (TFO)

Standard Owner:

Neil Curtis, Director - Grid and Market Operations

AESO Requirement Owner(s):

Neil Curtis, Director - Grid and Market Operations

AESO Subject Matter Expert(s):

Work Group Comments:



Work Group Response:

Work Group Recommendation:

OWG members support the recommendation of this standard to the ARC.

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ARC Operation Work Group Assessment and Conversion of NERC MOD-010-0 and MOD-012-0 to Alberta MOD-010&012-AB-0 Steady-State and Dynamic Data for Transmission System Modeling and Simulation				
Section	NERC MOD-010-0 & MOD-012-0 ²⁴	Alberta MOD-010&012-AB-0	Reason for Difference ²⁵	Comments ²⁶
Purpose	To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.	<u>The purpose of this reliability standard is to provide for the delivery of data and information necessary to establish consistent data requirements, reporting procedures, power flow and dynamic system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.</u>	Clarified the purpose to align with the content of the reliability standard.	
Applicability	<p>4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1</p> <p>4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1</p> <p>4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1</p> <p>4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1</p>	<p><u>This reliability standard applies to:</u></p> <ul style="list-style-type: none"> Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1 Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1 GFOs ISO Transmission Owners specified in the data requirements and reporting procedures of MOD-011- 	The information contained in NERC standards MOD-010-0 and MOD-012-0 have been combined into one Alberta reliability standard MOD-010&012-AB-0. The “WECC Data Preparation Manual For Power Flow and Stability Studies” addresses the data submission requirements for both of these NERC standards.	

²⁴ Applicability section and requirements from NERC standard MOD-012-0 have been added in orange.

²⁵ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

²⁶ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC Operation Work Group Assessment and Conversion of NERC MOD-010-0 and MOD-012-0 to Alberta MOD-010&012-AB-0 Steady-State and Dynamic Data for Transmission System Modeling and Simulation				
Section	NERC MOD-010-0 & MOD-012-0 ²⁴	Alberta MOD-010&012-AB-0	Reason for Difference ²⁵	Comments ²⁶
	<p>4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R1</p> <p>4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R1</p> <p>4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R1</p> <p>4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R1</p>	<p><u>0_R1TFOs</u></p> <p>4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1</p> <p>4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R1</p> <p>4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R1</p> <p>4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R1</p> <p>4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R1</p>		
Effective Date	April 1, 2005	<u>ThirtyNinety</u> calendar days after the date of approval by the Commission. April 1, 2005		
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ²⁷	Added definitions section to the Alberta reliability standard.	
Requirement	R1. The Transmission Owners, Transmission Planners Generator	R1. <u>Each The TFOs and GFOs must provide appropriate equipment</u>		Participants are obligated under

²⁷ Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.
Draft: 2010-04-28 OWG recommendation to ARC (Highlighting indicates revisions since organization review)

ARC Operation Work Group Assessment and Conversion of NERC MOD-010-0 and MOD-012-0 to Alberta MOD-010&012-AB-0 Steady-State and Dynamic Data for Transmission System Modeling and Simulation				
Section	NERC MOD-010-0 & MOD-012-0 ²⁴	Alberta MOD-010&012-AB-0	Reason for Difference ²⁵	Comments ²⁶
	<p>Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011 0_R1.</p> <p>R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.</p>	<p>characteristics and system data to the ISO in compliance withas required by the ISO rules as identified in the Alberta reliability standards reference table on the AESO website.</p> <p>R2.- TThe Transmission Owners, Transmission Planners Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shallISO, subject to requirement R3, must provide appropriate equipment characteristics, system data, dynamics system modeling, simulation data and existing and future hinterchange Sschedules to the WECC in compliance with the requirements for an “Area Coordinator” as specified in the current version of the “WECC Data Preparation Manual For Power Flow and Stability Studies”.with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011 0_R1.</p>	<p>Identified the applicable WECC document in R2.</p>	<p>OPP 1306 to provide the ISO with this data.</p>

ARC Operation Work Group Assessment and Conversion of NERC MOD-010-0 and MOD-012-0 to Alberta MOD-010&012-AB-0 Steady-State and Dynamic Data for Transmission System Modeling and Simulation				
Section	NERC MOD-010-0 & MOD-012-0 ²⁴	Alberta MOD-010&012-AB-0	Reason for Difference ²⁵	Comments ²⁶
		R1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.		
Measure		<u>MR1. Confirmation exists that data and information has been is provided as specified in accordance with requirement R1.</u> <u>MR2. Confirmation exists that data and information has been is provided as specified in accordance within requirement R2.</u>		
Requirement	R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and	R2R3. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements		

ARC Operation Work Group Assessment and Conversion of NERC MOD-010-0 and MOD-012-0 to Alberta MOD-010&012-AB-0 Steady-State and Dynamic Data for Transmission System Modeling and Simulation				
Section	NERC MOD-010-0 & MOD-012-0 ²⁴	Alberta MOD-010&012-AB-0	Reason for Difference ²⁵	Comments ²⁶
	<p>reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).</p> <p>R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).</p>	<p>and reporting procedures of MOD-011-0_R1) shall ISO must provide this <u>the data and information specified steady-state modeling and simulation data in requirement R2 according to the to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. WECC according to the data bank compilation schedule published by WECC for the current year; provided that, if no such schedule exists, then these entities such data and information must be shall provided the data upon request no later than within 30 calendar days from the date it is requested by the WECC.</u></p> <p>R2. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable</p>		

ARC Operation Work Group Assessment and Conversion of NERC MOD-010-0 and MOD-012-0 to Alberta MOD-010&012-AB-0 Steady-State and Dynamic Data for Transmission System Modeling and Simulation				
Section	NERC MOD-010-0 & MOD-012-0 ²⁴	Alberta MOD-010&012-AB-0	Reason for Difference ²⁵	Comments ²⁶
		reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).		
Measure	M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2.	M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2. MR3 Confirmation exists that data and information has been is provided in accordance with the timelines as specified in requirement R3.		
Procedures				
Compliance	To view the compliance section D of the NERC reliability standards follow these links: http://www.nerc.com/files/MOD-010-0.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards.	

ARC Operation Work Group Assessment and Conversion of NERC MOD-010-0 and MOD-012-0 to Alberta MOD-010&012-AB-0 Steady-State and Dynamic Data for Transmission System Modeling and Simulation				
Section	NERC MOD-010-0 & MOD-012-0²⁴	Alberta MOD-010&012-AB-0	Reason for Difference²⁵	Comments²⁶
	http://www.nerc.com/files/MOD-012-0.pdf		<p>A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta.</p> <p>This approach is deemed consistent with the existing ISO Rules.</p>	
Regional Differences	None identified.		Not applicable in Alberta	



Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

- Commission
- day
- generating facility owner (GFO)
- interchange schedule
- Interconnection
- ISO
- reliability
- reliability standard
- transmission facility owner (TFO)
- Western Electric Coordinating Council (WECC)

Standard Owner:

Pamela Mclean, Technical Lead – Power System Model Management

AESO Requirement Owner(s):

Sami Abdulsalam, Technical Services Senior Engineer

AESO Subject Matter Expert(s):

Pamela Mclean, Technical Lead – Power System Model Management

Work Group Comments:

1. The OWG members want to see the cross reference table to the ISO rules before or with stakeholder consultation.

Draft: 2010-04-28 OWG recommendation to ARC (Highlighting indicates revisions since organization review)



2. The OWG members want to change “confirmation” to “evidence” in MR1. The OWG members request the ISO to identify what “evidence” means.
3. Recommendation to include reference to the “reference table” in the requirements.
4. ENMAX, TransAlta and Suncor would like more lead time for producing evidence and training, recommend 6 months after approval by the Commission for all reliability standards.
5. Capital Power would like more lead time for producing evidence and training, recommend 90 days after approval by the Commission for all reliability standards.

ISO Response:

The following are the responses from the ISO on the above items:

1. The ISO will prepare the cross reference table to the ISO rules by the time of stakeholder consultation on this standard.
2. The ISO will prepare an explanation of what “confirmation” means and provide it to the OWG and ARC members.
3. Included a reference to the Alberta reliability standards reference table on the AESO website in requirement R1.
4. and 5. The ISO has revised the effective date from thirty to ninety calendar days after the date of approval by the Commission.

Work Group Recommendation:

OWG members support the recommendation of this standard to the ARC and will review ISO changes to the standard when the ISO sends the standard to the ARC members.

Developed by:



Name	Organization	Role
Pamela Mclean	AESO	Standard Owner and Subject Matter Expert
Doug Hincks	AESO	OWG Chair
Jerry Mossing	AESO	OWG member
Ken Gardner	AESO	Reliability Standards Technical Specialist
Don Olson	AESO	OWG member (preliminary review)
Elizabeth Olivier	Consultant	Technical Writer review
Larry Kram	AESO	Legal review
John Walker	ATCO Power	OWG member (preliminary review)
Dwayne Aasberg	Dow Chemical	OWG member
Teri Haffick	ENMAX	OWG member (preliminary review)
Anirban Bosu	TransAlta	OWG member
Dan Bamber	TransAlta	OWG member
Blaine Beisiegel	ATCO Electric	OWG member
Rick Spyker	AltaLink	OWG member
Kevin Neithercut	ENMAX	OWG member
Mark Thompson	AESO	OWG member (preliminary review)
Michael Taylor	Capital Power	OWG member
Neil Curtis	AESO	OWG – Alternate Chair
Stew Purkis	City of Lethbridge	OWG member
Chris Best	TransCanada	OWG member
Gerry Young	Suncor	OWG member
Roy Hanson	ENMAX CEC	OWG member
Cal Lenz	ATCO Power	OWG member



Name	Organization	Role
Subrota Bairgi	Suncor	OWG member
Amber Kirby	Capital Power	OWG member
Blaise Smith	TransAlta	OWG member
Penny Haldane	ENMAX	OWG member



[RETURN TO AGENDA](#)

ARC Operations Work Group Assessment and Conversion of NERC PER-003-0 to Alberta PER-003-AB-0 Operating Personnel Credentials				
Section	NERC PER-003-0	Alberta PER-003-AB-0	Reason for Difference ²⁸	Comments ²⁹
Purpose	Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System.	<u>The purpose of this reliability standard is to ensure that real-time operating personnel that are responsible for the reliable operation of the bulk electric system</u> BES hold NERC system operator certification. Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System.		
Applicability	4.1. Transmission Operators. 4.2. Balancing Authorities. 4.3. Reliability Coordinators.	<u>This reliability standard applies to the following:</u> <ul style="list-style-type: none"> <u>ISO</u> <u>TFOs that operate or direct a portion of the operation of the BES</u>bulk electric system under their own authority. Transmission Operators. Balancing Authorities. 4.3. Reliability Coordinators.		

²⁸ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

²⁹ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operations Work Group Assessment and Conversion of NERC PER-003-0 to Alberta PER-003-AB-0
Operating Personnel Credentials**

Section	NERC PER-003-0	Alberta PER-003-AB-0	Reason for Difference ²⁸	Comments ²⁹
Effective Date	April 1, 2005	Thirty calendar days <u>Six months after the date of approval by the Commission.</u> April 1, 2005		
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ³⁰	Added definitions section to the Alberta reliability standard.	
Requirement	R1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:	R1 Subject to R1.1, the ISO and each Transmission Operator <u>TFO that operates the BES bulk electric system under their own authority, either directly or through communications with others,</u> -, Balancing Authority, and Reliability Coordinator shall <u>must</u> staff all <u>real-time</u> operating positions that have the primary responsibility, at all times either directly or through communications with others, for the real-time operation of the interconnected Bbulk Eelectric Ssystem meet both of the following criteria with personnel <u>who hold a valid that are NERC system operator certification</u> <u>as follows:</u> <ul style="list-style-type: none"> <u>ISO, as either NERC Reliability</u> 	Added specific certification required by the ISO and TFOs. Added exceptions to the requirement to address acceptable situations where NERC certification of real-time operations staff is not required including the items identified in the measures in the NERC reliability standard.	<u>RO – Neil Curtis</u>

³⁰ Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.
Draft: 2010-04-28 OWG recommendation to ARC (Highlighting indicates revisions since organization review)

ARC Operations Work Group Assessment and Conversion of NERC PER-003-0 to Alberta PER-003-AB-0 Operating Personnel Credentials				
Section	NERC PER-003-0	Alberta PER-003-AB-0	Reason for Difference ²⁸	Comments ²⁹
		<p>Operator <u>or NERC Balancing, Interchange and Transmission, TFOs, as either NERC Reliability Operator, NERC Balancing, Interchange and Transmission or NERC Transmission Operator.</u></p> <p><u>R1.1 Requirement R1 does not apply as follows:</u> for the applicable functions: <u>subject to with the following exceptions:</u></p> <p><u>R1.1.1 R1.1</u> the real-time operating personnel may be assisted by a system operator trainee who must always be under <u>Each system operator trainees that performs a critical tasks must do so the operator's under the direct, continuous supervision and observation of the the an operator who holds a valid NERC system operator certification NERC-certified individual; or.</u></p> <p><u>R1.1.2 R1.2</u> During an real-time operating emergency for up to a four <u>4 hour period when the real-</u></p>		

ARC Operations Work Group Assessment and Conversion of NERC PER-003-0 to Alberta PER-003-AB-0 Operating Personnel Credentials				
Section	NERC PER-003-0	Alberta PER-003-AB-0	Reason for Difference ²⁸	Comments ²⁹
		<p>time system operating personnel's operator's control is transferred from a primary control center pursuant to (what would authorize the transfer...another reliability standard??) to a backup control center; or</p> <p>R1.1.3 To a TFO whose only bulk electric system transmission facilities are radial line(s) connecting a generating unit to the Alberta Interconnected Electric System.</p> <p>R1.3 Operating positions that do not operate the bulk electric system under their own authority.</p>		
Measure	<p>M1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall have NERC-certified operating personnel on shift in required positions at all times with the following exceptions:</p> <p>M1.1 While in training, an individual</p>	<p>M1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall have NERC-certified real time operating personnel on shift in required positions at all times with the following exceptions:MR1 A list of real-time operating positions exists as specified in requirement defined in R1 exists. Evidence exists that each</p>		

**ARC Operations Work Group Assessment and Conversion of NERC PER-003-0 to Alberta PER-003-AB-0
Operating Personnel Credentials**

Section	NERC PER-003-0	Alberta PER-003-AB-0	Reason for Difference ²⁸	Comments ²⁹
	<p>without the proper NERC certification credential may not independently fill a required operating position. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-certified individual filling the required position.</p> <p>M1.2 During a real-time operating emergency, the time when control is transferred from a primary control center to a backup control center shall not be included in the calculation of non-compliance. This time shall be limited to no more than four hours.</p>	<p>operator holds a the valid Evidence of NERC system operator reliability certification as Reliability Coordinators certificate. is available for each operator indicating the NERC certificate #.</p> <p>MR1.1 Measures for R1.1 are included in the subsections below.</p> <p>MR1.1.1 Evidence exists that could include, but is not limited to, such as shift schedules, Operator logs, voice recordings, or other data exists that verify the operator in control for all real-time operations. Documentation exists stating a system operator indicating <u>Written procedures and training document exist indicating trainee's area of responsibility and authority within the control centre.</u></p> <p>MR1.1.2 Evidence exists that could include, but is not limited to, Disturbance reports, operator logs, voice recordings and/or other evidence that shows an emergency requiring the transfer to the backup control centre</p>		

**ARC Operations Work Group Assessment and Conversion of NERC PER-003-0 to Alberta PER-003-AB-0
Operating Personnel Credentials**

Section	NERC PER-003-0	Alberta PER-003-AB-0	Reason for Difference ²⁸	Comments ²⁹
		<p><u>has occurred, and confirms the time of transfer was less than four 4-hours. Where transfer to the backup control centre exceeded four hours, evidence exists which demonstrates the operator(s) responsible in control for all real-time operations holds a valid NERC system operator certification.</u></p> <p>MR1.1.3 Evidence exists that shows the TFO's only bulk electric system transmission facilities are radial line(s) connecting a generating unit to the Alberta Interconnected Electric System.</p>		
Requirement	R1.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.	<p>R1.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.</p>	The applicability section includes this criteria.	

ARC Operations Work Group Assessment and Conversion of NERC PER-003-0 to Alberta PER-003-AB-0 Operating Personnel Credentials				
Section	NERC PER-003-0	Alberta PER-003-AB-0	Reason for Difference ²⁸	Comments ²⁹
Measure		M1.1 While in training, an individual without the proper NERC certification credential may not independently fill a required operating position. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-certified individual filling the required position.		
Requirement	R1.2. Positions directly responsible for complying with NERC standards.	R1.2. Positions directly responsible for complying with NERC standards.	Positions in Alberta are responsible to comply with Alberta reliability standards and this reliability standard addresses those positions that require staff with appropriate NERC system operator certification.	
Measure		M1.2 During a real-time operating emergency, the time when control is transferred from a primary control center to a backup control center shall not be included in the calculation of non-compliance. This time shall be limited to no more than four hours.		
Procedures				
Compliance	To view the compliance section D of the NERC reliability standard		There is no compliance section currently	

ARC Operations Work Group Assessment and Conversion of NERC PER-003-0 to Alberta PER-003-AB-0 Operating Personnel Credentials				
Section	NERC PER-003-0	Alberta PER-003-AB-0	Reason for Difference²⁸	Comments²⁹
	follow this link: http://www.nerc.com/files/PER-003-0.pdf		<p>proposed in the Alberta Reliability Standards.</p> <p>A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta.</p> <p>This approach is deemed consistent with the existing ISO Rules.</p>	
Regional Differences	None identified.		Not applicable in Alberta	



Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

Commission

day

bulk electric system (BES)

ISO

NERC

reliability standard

transmission facility owner (TFO)

Standard Owner:

Neil Curtis, Director - Grid and Market Operations

AESO Requirement Owner(s)

Neil Curtis, Director - Grid and Market Operations for all requirements.

AESO Subject Matter Expert(s):

Work Group Comments:

1. Recommend changing the effective date to six months after approval by the Commission.
2. Recommend that TFOs with radial transmission lines connecting a generator to the transmission system should be exempt from this reliability standard.

ISO Response:



The following are the responses from the ISO on the above items:

1. The effective date of this reliability standard has been changed to six months as requested.
2. Added requirement R1.1.3 to address this concern.

Work Group Recommendation:

OWG members will review ISO changes to the standard when the ISO sends the standard to the ARC members.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	OWG member
Doug Hincks	AESO	OWG Chair
Neil Curtis	AESO	OWG Alternate Chair
Ken Gardner	AESO	Reliability Standard Specialist
Anirban Bosu	TransAlta	OWG member
Ron Smith	AESO	OWG member
Mark Thompson	AESO	OWG member
Peter Tam	AESO	OWG member
Roy Hansen	ENMAX	OWG member
Elizabeth Olivier	Consultant	Technical Writer review
Ravinder Farwaha	Suncor	OWG member
Larry Kram	AESO	Legal review
Gerry Young	ATCO Power	OWG member
John Walker	Suncor	OWG member
Chris Best	TransCanada	OWG member
Rick Spyrker	Airlink	OWG member
Terri Haffick	ENMAX	OWG member
Blaine Beisiegel	ATCO Electric	OWG member
Kevin Neithercut	ENMAX	OWG member
Subota Baragi	Suncor	OWG member



Dan Bamber	TransAlta	OWG member
Dwayne Aasberg	Dow Chemical	OWG member
Amber Kirby	Capital Power	OWG member
Michael Taylor	Capital Power Corp.	OWG member
Stew Purkis	City of Lethbridge	OWG member
Cal Lenz	ATCO Power	OWG member
Blaise Smith	TransAlta	OWG member
Penny Haldane	ENMAX	OWG member

ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1				
System Personnel Training				
Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
Purpose	To ensure that System Operators performing real-time, reliability-related tasks on the North American Bulk Electric System (BES) are competent to perform those reliability-related tasks. The competency of System Operators is critical to the reliability of the North American Bulk Electric System.	<u>The purpose of this reliability standard is to ensure that System Operators</u> performing real-time, reliability-related tasks on the <u>North American Bulk Electric System</u> <u>bulk electric system</u> <u>have the requisite skills and training and are competent</u> (BES) are competent to perform those reliability-related tasks. The competency of System Operators operators is critical to the reliability of the North American Bulk bulk Electric electric Systems system.		
Applicability	4.1.1 Reliability Coordinator. 4.1.2 Balancing Authority. 4.1.3 Transmission Operator.	<u>This reliability standard applies to:</u> • ISO • TFOs 4.1.1 Reliability Coordinator. 4.1.2 Balancing Authority. 4.1.3 Transmission Operator.		
Effective Date	5.1. In those jurisdictions where regulatory approval is required, Requirement R1 and Requirement R2 shall become effective on the	5.1. In those jurisdictions where regulatory approval is required, Requirement R1 and Requirement R2 shall become <u>effective on the first</u>		

³¹ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

³² Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
	<p>first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R1 and Requirement R2 shall become effective on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.</p> <p>5.2. In those jurisdictions where regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter after Board of Trustees adoption.</p> <p>5.3. In those jurisdictions where regulatory approval is required Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after applicable regulatory approval. In those jurisdictions</p>	<p>day of the first calendar quarter, 24 months after applicable regulatory the date of approval by the Commission. In those jurisdictions where no regulatory approval is required, Requirement R1 and Requirement R2 shall become effective on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.</p> <p>5.2. In those jurisdictions where regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter 12 months after applicable regulatory the date of approval by the Commission. In those jurisdictions where no regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter after Board of Trustees adoption.</p> <p>5.3. In those jurisdictions where regulatory approval is required Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after the date of applicable regulatory approval by the Commission. In those</p>		

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
	where no regulatory approval is required, the Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after Board of Trustees adoption.	jurisdictions where no regulatory approval is required, the Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after Board of Trustees adoption.		
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ³³	Added definitions section to the Alberta reliability standard.	
Requirement	R1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. <i>[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]</i>	company-specific reliability-related tasks performed by its System Operators and, shall implement the program. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1 The ISO and Each Reliability Coordinator, Balancing Authority and Transmission Operator shall TFO must use a systematic approach to training to establish a training program for real-time operating personnel for the BES bulk electric system company-specific reliability-related tasks performed by its System operating personnel. The ISO and each TFO must implement ors and		RO – Doug Hincks

³³ Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
		<p>shall <u>must implement</u> the <u>training</u> program. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]</p>		
Measure	<p>M1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence of using a systematic approach to training to establish and implement a training program, as specified in R1.</p>	<p>MR1 <u>Evidence exists and shows that</u> Each Reliability Coordinator, Balancing Authority and Transmission Operator shall <u>The ISO and each TFO have available for inspection evidence of using</u> a systematic approach to training <u>was taken</u> to establish and implement a training program as specified in <u>requirement</u> R1.</p>		
Requirement	<p>R1.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators.</p>	<p>R1.1 <u>The ISO and Each each TFO Reliability Coordinator, Balancing Authority and Transmission Operator shall</u> <u>must develop, maintain and update at least once per calendar year, create</u> a list of <u>BES-bulk electric system</u> company-specific reliability-related tasks performed by its System <u>operating personnel</u>.</p>		RO – Neil Curtis

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
Measure	M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its company-specific reliability-related task list, with the date of the last review and/or revision, as specified in R1.1.	MR1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its a list of bulk electric system company-specific reliability-related tasks list exists with the date of the last review and/or revision, as specified in requirement R1.1. The list of bulk electric system company-specific reliability-related tasks has been reviewed and updated as specified in requirement ISO and each TFO have evidence which demonstrates the list identified in R1.1 of bulk electric system has been reviewed and updated each calendar year. Where no change is required in a given year, evidence exists that which demonstrates the review occurred and resulted in no change to the list as specified in requirement R1.1.		
Requirement	R1.1.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed by its System Operators each calendar year to identify new or modified tasks for	R1.1.1 The ISO and Each TFO must review and Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES bulk electric system company-specific reliability-related tasks performed by its System Operating personnel each calendar year to identify new or	Rolled this in to R1.1	RO – Neil Curtis

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
	inclusion in training.	modified tasks for inclusion in training.		
Measure				
Requirement	R1.2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1.	R1.2 The ISO and E each TFO must Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in <u>requirement</u> R1.1.	Alberta Variance³⁴: NERC appears to require the responsible entity to create training materials themselves. Changes made in the Alberta reliability standard permit the use of joint or third party training.	RO – Doug Hincks

³⁴ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
Measure	M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its learning objectives and training materials, as specified in R1.2.	MR1.2 <u>Evidence exists and shows that</u> Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall <u>T ISO and each TFO have learning objectives were designed and developed evidence have available for inspection of its learning objectives and training materials</u> as specified in <u>requirement</u> R1.2.		
Requirement	R1.3. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2.	R1.3. The ISO and Each TFO Reliability Coordinator, Balancing Authority and Transmission Operator shall <u>must deliver provide</u> the training <u>for each operating personnel real-time operating personnel to meet the learning objectives</u> established in <u>requirement</u> R1.2.	Alberta Variance³⁵: NERC appears to require the responsible entity to deliver the training themselves. Changes made in the Alberta reliability standard permit the use of joint or third party training.	RO – Doug Hincks
Measure	M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered and the dates of delivery to show	MR1.3 <u>Training was provided to each operating personnel real-time operating personnel as specified in requirement</u> R1.3. <u>Evidence exists that could include, but is not limited to, Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall</u> <u>The ISO and each TFO have</u>		

³⁵ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
	that it delivered the training, as specified in R1.3.	evidence of available for inspection System Operator operating personnel training records showing the names of the people trained <u>and the title of the scheduled date of training.</u> training delivered training and the date to demonstrate s of delivery to show that it delivered the t training was provided, as specified in R1.3.		
Requirement	R1.4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.	R1.4. The ISO and E <u>Each TFO must Reliability Coordinator, Balancing Authority and Transmission Operator</u> shall conduct an annual evaluation of the training program established in <u>requirement</u> R1, to identify any needed changes to the training program and shall <u>must</u> implement the changes identified.		RO – Doug Hincks

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
Measure	<p>M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an annual training program evaluation, as specified in R1.4</p>	<p>MR1.4 <u>The training program was evaluated annually as specified in requirement R1.4</u>Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall <u>The ISO and each TFO have, available for inspection</u>e<u>Evidence exists that could include, but is not limited to</u> (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments and, or internal audit results, that it performed an annual training program evaluation and implemented identified changes, as specified in R1.4</p>		
Requirement	<p>R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator’s capabilities to perform each assigned task identified in R1.1 at least one time. <i>[Violation Risk Factor: High] [Time Horizon: Long-term Planning]</i></p>	<p>R2 The ISO and E<u>each TFO must Reliability Coordinator, Balancing Authority and Transmission Operator shall verify that each member of its real-time System Operator’s operating personnel’s is capable</u>ilities of performing each assigned task identified in the list in requirement R1.1, at least once time<i>[Violation Risk Factor: High] [Time Horizon: Long-term Planning]</i></p>	<p>Removed “at least one time” as this should be an ongoing obligation.</p>	<p>RO Neil Curtis</p>

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
Measure	<p>M2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence to show that it verified that each of its System Operators is capable of performing each assigned task identified in R1.1, as specified in R2. This evidence can be documents such as training records showing successful completion of tasks with the employee name and date; supervisor check sheets showing the employee name, date, and task completed; or the results of learning assessments.</p>	<p>MR2. <u>Evidence exists and shows that Each Reliability Coordinator, Balancing Authority and Transmission Operator shall</u>The ISO and each TFO have available for inspection evidence to show demonstrate that it verified that each of its System Operators<u>operating personnel</u>real-time operating personnel is capable of performing each assigned task identified in <u>requirement</u> R1.1, as specified in <u>requirement</u> R2. <u>This e</u>Evidence exists that could -may include, but is not limited to, can be documents such as training records showing successful completion of tasks with the <u>employee operating personnel</u>real-time operating personnel's name and date, <u>supervisor task assessment</u> check sheets showing the <u>employee operating personnel</u>real-time operating personnel's name, date, <u>and task(s) completed and signed by the operating personnel</u>real-time operating personnel's supervisor and ; or the results of <u>documented</u> learning assessments.</p>		
Requirement	<p>R2.1. Within six months of a modification of the BES company-specific reliability-related tasks,</p>	<p>R2.1. Within six months of a modification of the <u>BES-bulk electric system</u> company-specific reliability-</p>		<p><u>RO – Neil Curtis</u></p>

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
	each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.	related tasks, <u>the ISO and each TFO</u> Reliability Coordinator, Balancing Authority and Transmission Operator shall must verify <u>that</u> each <u>member</u> of its System Operator's operating personnel <u>real-time operating personnel</u> is capable ilities of <u>performing</u> the new or modified tasks.		
Measure		<u>MR2.1 Evidence exists and shows that each operating personnel real-time operating personnel is capable of performing new or modified tasks</u> Where a modification of the bulk electric system company-specific reliability related tasks has occurred under requirement R1.1.1., the ISO and each TFO have evidence of training in accordance with R2.1.		
Requirement	R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other	R3. At least every 12 months <u>the ISO and each TFO</u> Reliability Coordinator, Balancing Authority and Transmission Operator shall must provide each each member of its operating personnel <u>real-time operating personnel</u> System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes, <u>but is not limited to,</u>		<u>RO – Doug Hincks</u>

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
	training required to maintain qualified personnel. <i>[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]</i>	system restoration using drills, exercises and or other training required to maintain qualified personnel. <i>[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]</i>		
Measure	M3. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection training records that provide evidence that each System Operator has obtained 32 hours of emergency operations training, as specified in R3.	MR3. Evidence exists and shows that <u>all operating personnel real-time operating personnel have completed at least 32 hours of emergency operations training, as specified in requirement R3.</u> Evidence could include, but is not limited to, Each Reliability Coordinator, Balancing Authority and Transmission Operator shall <u>The ISO and each TFO have evidence such as</u> have available for inspection training records, that provide evidence that demonstrate each System Operator <u>all operating personnel have</u> obtained completed at least 32 hours of emergency operations training, as specified in R3.		
Requirement	R3.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL	R3.1. The ISO and Each each TFO Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities facilities <u>interconnection reliability operating limits</u> IROLs or has established operating guides or protection systems		RO - Doug Hincks

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference ³¹	Comments ³²
	<p>violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.</p>	<p>to mitigate <u>interconnection reliability operating limit</u> violations shall <u>must</u> provide each <u>member of its operating personnel</u> real-time operating personnel System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the <u>BES-bulk electric system</u> during normal and emergency conditions.</p>		
Measure	<p>M3.1 Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection training records that provide evidence that each System Operator received emergency operations training using simulation technology, as specified in R3.1.</p>	<p>MR3.1 <u>Evidence exists and shows that each operating personnel real-time operating personnel received emergency operations training using simulation technology, as specified in requirement R3.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall The ISO and each TFO have available for inspection Evidence could include, but is not limited to, -such as training records, -that provide evidence that demonstrate each System Operator operating personnel received emergency operations training using simulation technology, as specified in R3.1.</u></p>		

**ARC Operations Work Group Assessment and Conversion of NERC PER-005-1 to Alberta PER-005-AB-1
System Personnel Training**

Section	NERC PER-005-1	Alberta PER-005-AB-1	Reason for Difference³¹	Comments³²
		<u>Evidence the simulation technology exists.</u>		
Procedures				
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/PER-005-1.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	None identified.		Not applicable in Alberta	



Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

Standard Owner:

Doug Hincks, Director – Operations Support

AESO Requirement Owner(s):

Doug Hincks, Director – Operations Support for requirements R1, R1.2 to R1.4, R3 and R3.1

Neil Curtis, Director, Grid and Market Operations for requirements R1.1, R1.1.1, R2 and R2.1

AESO Subject Matter Expert(s):

Work Group Comments:

Note: This reliability standard has not been approved by FERC.

ISO Response:

In the Alberta reliability standards development process, reliability standards are assessed for application in Alberta after standards are approved by the NERC BOT, this is in accordance with the reliability standards project terms of reference.

Work Group Recommendation:

OWG members support the recommendation of this standard to the ARC.

Developed by:

Name	Organization	Role
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Name	Organization	Role
Bruce Fauvelle	AESO	SME
Ken Gardner	AESO	Reliability Standards Specialist
Jerry Mossing	AESO	OWG member
Doug Hincks	AESO	OWG Chair
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Name	Organization	Role
Amber Kirby	Capital Power	OWG member
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Cal Lenz	ATCO Power	OWG member
Amber Kirby	Capital Power	OWG member
Blaise Smith	TransAlta	OWG member
Penny Haldane	ENMAX	OWG member

ARC Operation Work Group Assessment and Conversion of NERC PRC-007- 0 to Alberta PRC-007-AB-0				
Assuring Consistency with Regional UFLS Program Requirements				
Section	NERC PRC-007-0	Alberta PRC-007-AB-0	Reason for Difference ³⁶	Comments ³⁷
Purpose	Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.	<u>The purpose of this reliability standard is to</u> Provide <u>provide</u> last resort system preservation measures by implementing an Under Frequency Load Shedding UFLS program.		
Applicability	<p>4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program</p> <p>4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program</p> <p>4.3. Distribution Provider required by its Regional Reliability Organization to own or operate a UFLS program</p> <p>4.4. Load-Serving Entity required by its Regional Reliability Organization to operate a UFLS program</p>	<p><u>This reliability standard applies to:</u></p> <ul style="list-style-type: none"> • <u>ISO</u> • 4.1. Transmission Owner required by its Regional Reliability Organization to own a UFLS program <u>TFOs that own or operate relays as part of the UFLS program set out in the ISO rules, as identified in the Alberta reliability standards reference table on the AESO website, that own or operate a UFLS program;</u> 4.2. Transmission Operator required by its Regional Reliability Organization to operate a UFLS program • 4.3. Distribution 		Reference is to OPP 804 Off-Nominal Frequency Load Shedding and Restoration.

³⁶ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

³⁷ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operation Work Group Assessment and Conversion of NERC PRC-007- 0 to Alberta PRC-007-AB-0
Assuring Consistency with Regional UFLS Program Requirements**

Section	NERC PRC-007-0	Alberta PRC-007-AB-0	Reason for Difference ³⁶	Comments ³⁷
		<p>Provider <u>Demand customers that have an obligation to shed load as part of the UFLS program set out in the ISO rules, as identified in the Alberta reliability standards reference table on the AESO website, required by its Regional Reliability Organization to that own or operate a UFLS program.</u></p> <p><u>4.4. Load-Serving Entity required by its Regional Reliability Organization to operate a UFLS program</u></p>		
Effective Date	April 1, 2005	<p>Thirty <u>Ninety calendar days after the date of approval by the Commission.</u></p> <p><u>April 1, 2005</u></p>		
Definitions		<p>Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.³⁸</p>	<p>Added definitions section to the Alberta reliability standard.</p>	
Requirement	<p>R1. The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization)</p>	<p>R1 The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall <u>ISO</u></p>		<p>Requirement Owner for R1 – John Kehler</p> <p><u>Reference is to OPP</u></p>

³⁸ Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.

**ARC Operation Work Group Assessment and Conversion of NERC PRC-007- 0 to Alberta PRC-007-AB-0
Assuring Consistency with Regional UFLS Program Requirements**

Section	NERC PRC-007-0	Alberta PRC-007-AB-0	Reason for Difference ³⁶	Comments ³⁷
	shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.	must ensure that its the UFLS program set out in the ISO rules for Alberta, as identified in the Alberta reliability standards reference table on the AESO website, is consistent with its Regional Reliability Organization's the WECC UFLS program requirements.		804 Off-Nominal Frequency Load Shedding and Restoration
Measure	M1. Each Transmission Owner's and Distribution Provider's UFLS program shall be consistent with its associated Regional Reliability Organization's UFLS program requirements.	MR1 Each Transmission Owner's and Distribution Provider Evidence exists that t The ISO's UFLS program exists and shall be is consistent with its associated Regional Reliability Organization's the WECC UFLS program requirements as specified in requirements in accordance with R1.		

**ARC Operation Work Group Assessment and Conversion of NERC PRC-007- 0 to Alberta PRC-007-AB-0
Assuring Consistency with Regional UFLS Program Requirements**

Section	NERC PRC-007-0	Alberta PRC-007-AB-0	Reason for Difference ³⁶	Comments ³⁷
Requirement	<p>R2. The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.</p>	<p>R2 Each TFOs and demand customer and The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity Wire Owners <u>owns or operates a UFLS program (as required by the ISO its Regional Reliability Organizations shall must provide, and annually annually update, and provide to the ISO, its their underfrequency data annually, provide the to the ISO as required by the ISO necessary for its Regional Reliability Organization to maintain and update a UFLS program database.</u></p> <p>R3 The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall <u>ISO must provide the, and annually update, its underfrequency data data it receives to the WECC in accordance with reliability standard MOD-010&12-AB. to as necessary for its Regional Reliability</u></p>		Requirement owner for R3 -Pamela Mclean

**ARC Operation Work Group Assessment and Conversion of NERC PRC-007- 0 to Alberta PRC-007-AB-0
Assuring Consistency with Regional UFLS Program Requirements**

Section	NERC PRC-007-0	Alberta PRC-007-AB-0	Reason for Difference ³⁶	Comments ³⁷
		<p>Organization in order for the WECC to enable the WECC to maintain and update a UFLS program database. Transmission Owner, Transmission Operator, Distribution Provider, and Load Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shallISO must provide, and annually update, its underfrequency data as necessary for the WECC its Regional Reliability Organization to maintain and update a UFLS program database.</p>		
Measure		<p><u>MR2 Evidence exists that the under frequency data described in requirement R2 was annually updated and provided by each TFO and demand customer to the ISO in accordance with requirement R2.</u></p> <p><u>MR3 Evidence exists that the under frequency data data described in requirement R3 was provided by the ISO to the WECC as specified in accordance with requirement R3.</u></p>		
Requirement	R3. The Transmission Owner and	R443 The Transmission Owner and		Requirement Owner

**ARC Operation Work Group Assessment and Conversion of NERC PRC-007- 0 to Alberta PRC-007-AB-0
Assuring Consistency with Regional UFLS Program Requirements**

Section	NERC PRC-007-0	Alberta PRC-007-AB-0	Reason for Difference ³⁶	Comments ³⁷
	Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).	Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall <u>ISO must provide the ISO rule, as identified in the Alberta reliability standards reference table on the AESO website, which sets out the its documentation of that UFLS program, which includes, but is not limited to,) to its Regional Reliability Organization the WECC upon request within 30 calendar days of WECC's request.</u>		for R4 – John Kehler Reference is to OPP 804 Off-Nominal Frequency Load Shedding and Restoration
Measure	M2. Each Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program shall have evidence that it provided its associated Regional Reliability Organization and NERC with documentation of the UFLS program on request (30 calendar days).	<u>MR42 Evidence exists that the ISO provided the ISO rule its as specified in accordance with requirement R4.</u> M2. Each Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program shall have evidence that it provided its associated Regional Reliability Organization and NERC with documentation of the UFLS program on request (30 calendar days).		
Procedures				
Compliance	To view the compliance section D		There is no compliance	

**ARC Operation Work Group Assessment and Conversion of NERC PRC-007- 0 to Alberta PRC-007-AB-0
Assuring Consistency with Regional UFLS Program Requirements**

Section	NERC PRC-007-0	Alberta PRC-007-AB-0	Reason for Difference³⁶	Comments³⁷
	of the NERC reliability standard follow this link: http://www.nerc.com/files/PRC-007-0.pdf		<p>section currently proposed in the Alberta Reliability Standards.</p> <p>A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta.</p> <p>This approach is deemed consistent with the existing ISO Rules.</p>	
Regional Differences	None identified.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

- days
- demand customer
- ISO



- reliability standard
- system
- transmission facility owner (TFO)
- underfrequency
- under frequency load shedding (UFLS)
- WECC

Standard Owner:

Jerry Mossing, Director - Transmission Support

AESO Requirement Owner(s):

John Kehler for requirements R1 and R4.

Pamela Mclean for requirement R3.

AESO Subject Matter Expert(s):

Henry Ren

Isabel Pana

Steve Heidt

Pamela McLean

Work Group Comments:

1. The OWG members want to see the cross reference table to the ISO rules before or with stakeholder consultation.
2. Recommendation to include reference to the “reference table” in the requirements.

ISO Response:

The following are the responses from the ISO on the above items:



1. The ISO will prepare the cross reference table to the ISO rules by the time of stakeholder consultation on this standard.
2. References to the Alberta reliability standards reference table on the AESO website were added to the requirements as requested.

Work Group Recommendation:

OWG members support the recommendation of this standard to the ARC and will review ISO changes to the standard when the ISO sends the standard to the ARC members.

Developed by:

Name	Organization	Role
Isabel Pana	AESO	Subject Matter Expert
Henry Ren	AESO	Subject Matter Expert
Ken Gardner	AESO	Reliability Standard Specialist
Jerry Mossing	AESO	OWG member
Doug Hincks	AESO	OWG Chair
Neil Curtis	AESO	OWG Alternate Chair
Kevin Wiens	AESO	Subject Matter Expert
John Kehler	AESO	Subject Matter Expert
Pamela Mclean	AESO	Subject Matter Expert
Larry Kram	AESO	Legal review
Galen Lam	AESO	Subject Matter Expert
Elizabeth Olivier	Consultant	Technical Writer
Anirban Bosu	TransAlta	OWG member
Ron Smith	AESO	OWG member



Name	Organization	Role
Mark Thompson	AESO	OWG member
Peter Tam	AESO	OWG member
John Walker	ATCO Power	OWG member
Rick Spyker	Altalink	OWG member
Blaine Beisiegel	ATCO Electric	OWG member
Subrota Bairagi	Suncor	OWG member
Roy Hanson	ENMAX	OWG member
Ravinder Farwaha	Suncor	OWG member
Gerry Young	Suncor	OWG member
Chris Best	TransCanada	OWG member
Terri Haffick	ENMAX	OWG member
Kevin Neithercut	ENMAX	OWG member
Dan Bamber	TransAlta	OWG member
Dwayne Aasberg	Dow Chemical	OWG member
Amber Kirby	Capital Power	OWG member
Michael Taylor	Capital Power Corp.	OWG member
Stew Purkis	City of Lethbridge	OWG member
Cal Lenz	ATCO Power	OWG member
Amber Kirby	Capital Power	OWG member
Blaise Smith	TransAlta	OWG member
Penny Haldane	ENMAX	OWG member

ARC Operation Work Group Assessment and Conversion of NERC PRC-008-0 to Alberta PRC-008-AB-0 Underfrequency Load Shedding Equipment Maintenance Programs				
Section	NERC PRC-008-0	Alberta PRC-008-AB-0	Reason for Difference ³⁹	Comments ⁴⁰
Purpose	Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program.	<u>The purpose of this reliability standard is to</u> provide last resort system preservation measures by implementing a n Under Frequency Load Shedding (UFLS) program.		
Applicability	<p>4.1. Transmission Owner required by its Regional Reliability Organization to have a UFLS program</p> <p>4.2. Distribution Provider required by its Regional Reliability Organization to have a UFLS program</p>	<p><u>This reliability standard applies to:</u></p> <ul style="list-style-type: none"> 4.1. Transmission Owner required by its Regional Reliability Organization to have a UFLS program <u>TFOs that own or operate relays as part of the UFLS program set out in the ISO rules, as identified in the Alberta reliability standards reference table on the AESO website.</u> 4.2. Distribution Provider required by its Regional Reliability Organization to have a UFLS program <u>demand customers that have an obligation to shed load as part of the UFLS program set out in the ISO rules, as identified in the</u> 		The UFLS program is implemented through OPP 804 Off-Nominal Frequency Load Shedding and Restoration.

³⁹ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

⁴⁰ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operation Work Group Assessment and Conversion of NERC PRC-008-0 to Alberta PRC-008-AB-0
Underfrequency Load Shedding Equipment Maintenance Programs**

Section	NERC PRC-008-0	Alberta PRC-008-AB-0	Reason for Difference ³⁹	Comments ⁴⁰
		<u>Alberta reliability standards reference table on the AESO website.</u>		
Effective Date	April 1, 2005	<u>One hundred and eighty</u> Thirty <u> calendar days after the date of approval by the Commission.</u> <u>April 1, 2005</u>		180 days aligns with PRC-005-AB-1.
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ⁴¹	Added definitions section to the Alberta reliability standard.	
Requirement	R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.	<u>R1 Each TFOs and demand customers must have a maintenance and testing program that includes UFLS equipment identification, and schedule(s) for UFLS equipment maintenance and testing.</u> R1. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program		

⁴¹ Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.

**ARC Operation Work Group Assessment and Conversion of NERC PRC-008-0 to Alberta PRC-008-AB-0
Underfrequency Load Shedding Equipment Maintenance Programs**

Section	NERC PRC-008-0	Alberta PRC-008-AB-0	Reason for Difference ³⁹	Comments ⁴⁰
		<p>shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.</p>		
Measure	<p>M1. Each Transmission Owner's and Distribution Provider's UFLS equipment maintenance and testing program contains the elements specified in Reliability Standard PRC-008-0_R1.</p>	<p><u>MR1 Documentation of equipment maintenance and testing program exists and includes elements as specified in accordance with requirement R1.</u></p> <p>M1. Each Transmission Owner's and Distribution Provider's UFLS equipment maintenance and testing program contains the elements specified in Reliability Standard PRC-008-0_R1.</p>		
Requirement	<p>R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).</p>	<p><u>R2 Each TFOs and demand customer must, as of the effective date of this reliability standard, implement its UFLS equipment maintenance and testing program in accordance with its equipment maintenance and testing program.</u></p> <p><u>R3 Each TFOs and demand customers must provide its UFLS maintenance and testing program results to the ISO within 30 calendar days of a request by the ISO.</u></p>	<p>Alberta Variance⁴²: UFLS maintenance and testing program results are sent to the ISO as the compliance monitor for TFOs and demand customers in Alberta.</p>	

⁴² An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

**ARC Operation Work Group Assessment and Conversion of NERC PRC-008-0 to Alberta PRC-008-AB-0
Underfrequency Load Shedding Equipment Maintenance Programs**

Section	NERC PRC-008-0	Alberta PRC-008-AB-0	Reason for Difference ³⁹	Comments ⁴⁰
		<p>R2. The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).</p>		
Measure	<p>M2. Each Transmission Owner and Distribution Provider shall have evidence that it provided the results of its UFLS equipment maintenance and testing program's implementation to its Regional Reliability Organization and NERC on request (within 30 calendar days).</p>	<p>MR2 Each Transmission Owner and Distribution Provider shall have evidence that it provided the results of its UFLS equipment maintenance and testing program's implementation to its Regional Reliability Organization and NERC on request (within 30 calendar days). <u>Evidence the maintenance and testing program exists which includes a list of each UFLS scheme that is part of the ISO UFLS program. Documentation exists to show that the maintenance and testing program has been implemented as specified in requirement R2. Evidence includes, but is not limited to may include</u></p>		

**ARC Operation Work Group Assessment and Conversion of NERC PRC-008-0 to Alberta PRC-008-AB-0
Underfrequency Load Shedding Equipment Maintenance Programs**

Section	NERC PRC-008-0	Alberta PRC-008-AB-0	Reason for Difference ³⁹	Comments ⁴⁰
		<p><u>status and inspection reports, work orders, and/or contracts.</u></p> <p><u>MR3 Confirmation that documentation as specified in R3 was received by the ISO or evidence exists that requests for confirmation were made as specified in requirement R3.</u></p>		
Procedures Compliance	<p>To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/PRC-008-0.pdf</p>		<p>There is no compliance section currently proposed in the Alberta Reliability Standards.</p> <p>A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta.</p> <p>This approach is deemed consistent with the existing ISO Rules.</p>	
Regional Differences	None identified.		Not applicable in Alberta	



Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

- Commission
- days
- demand customer
- ISO
- reliability standard
- system
- transmission facility owner (TFO)
- under frequency load shedding (UFLS)

Standard Owner:

Jerry Mossing, Director - Transmission Support

AESO Requirement Owner(s):

None required.

AESO Subject Matter Expert(s):

Isabel Pana
Henry Ren
John Kehler
Kevin Wiens
Pamela McLean

Work Group Comments:

1. The OWG members want to change “confirmation” to “evidence” in MR3. The OWG members request the ISO to identify what “evidence” means.
2. ATCO Electric is concerned with the implementation timelines for this reliability standard.



ISO Response:

The following are the responses from the ISO on the above items:

1. The ISO will prepare an explanation of what “confirmation” means and provide it to the OWG and ARC members.
2. The ISO will respond to the comments provided by ATCO Electric.

Work Group Recommendation:

OWG members support the recommendation of this standard to the ARC and will review ISO changes to the standard when the ISO sends the standard to the ARC members.

Developed by:

Name	Organization	Role
Isabel Pana	AESO	Subject Matter Expert
Henry Ren	AESO	Subject Matter Expert
Ken Gardner	AESO	Reliability Standard Specialist
Jerry Mossing	AESO	OWG member
Doug Hincks	AESO	OWG Chair
Neil Curtis	AESO	OWG Alternate Chair
Kevin Wiens	AESO	Subject Matter Expert
John Kehler	AESO	Subject Matter Expert
Pamela Mclean	AESO	Subject Matter Expert
Larry Kram	AESO	Legal review
Galen Lam	AESO	Subject Matter Expert



Name	Organization	Role
Elizabeth Olivier	Consultant	Technical Writer
Anirban Bosu	TransAlta	OWG member
Ron Smith	AESO	OWG member
Mark Thompson	AESO	OWG member
Peter Tam	AESO	OWG member
John Walker	ATCO Power	OWG member
Rick Spyker	Altalink	OWG member
Blaine Beisiegel	ATCO Electric	OWG member
Subrota Bairagi	Suncor	OWG member
Roy Hanson	ENMAX	OWG member
Ravinder Farwaha	Suncor	OWG member
Gerry Young	Suncor	OWG member
Chris Best	TransCanada	OWG member
Terri Haffick	ENMAX	OWG member
Kevin Neithercut	ENMAX	OWG member
Dan Bamber	TransAlta	OWG member
Dwayne Aasberg	Dow Chemical	OWG member
Amber Kirby	Capital Power	OWG member
Michael Taylor	Capital Power Corp.	OWG member
Stew Purkis	City of Lethbridge	OWG member
Cal Lenz	ATCO Power	OWG member
Amber Kirby	Capital Power	OWG member
Blaise Smith	TransAlta	OWG member



Name	Organization	Role
Penny Haldane	ENMAX	OWG member

ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0 UVLS System Scheme Maintenance and Testing				
Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
Purpose	Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.	Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Underunder voltage Load Shedding (UVLS) program. The purpose of this reliability standard is to ensure adequate maintenance and testing of <u>under Voltage Load Shedding (UVLS) programs</u> schemes is achieved.	Align the purpose with the requirements.	

⁴³ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

⁴⁴ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0 UVLS System Scheme Maintenance and Testing				
Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
Applicability	<p>4.1. Transmission Owner that owns a UVLS system</p> <p>4.2. Distribution Provider that owns a UVLS system</p>	<p><u>This reliability standard applies to:</u></p> <ul style="list-style-type: none"> • 4.1. Transmission Owner that owns a UVLS system TFOs that own a UVLS system scheme that is listed as a UVLS scheme in the ISO RAS database • – demand customers that own a UVLS system WOs that own a UVLS system scheme that is listed as a UVLS scheme in the ISO RAS database • demand customers that own a UVLS system scheme scheme that is listed as a UVLS scheme in the ISO RAS database • ISO 		

**ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0
UVLS ~~System Scheme~~ Maintenance and Testing**

Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
Effective Date		Ten Ninety calendar days after the date of approval by the Commission.		TWG members request 90 days to develop the maintenance testing program. Some members concerned that more time may be required depending on the number of UVLS schemes identified.
Definitions	April 1, 2005	Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ⁴⁵	Added definitions section to the Alberta reliability standard.	
Requirement	R1. The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:	R1. The Transmission Owner and Distribution Provider TFOs, DFWOs, or demand customers that owns a UVLS systemscheme shall must each have a UVLS equipment maintenance and testing program in place. This program must shall include:		

⁴⁵ Defined terms are not italicized in this document, but will appear in the Alberta Reliability Standards document.

**ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0
UVLS System Scheme Maintenance and Testing**

Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
Measure	M1. Each Transmission Owner and Distribution Provider that owns a UVLS system shall have documentation that its UVLS equipment maintenance and testing program conforms with Reliability Standard PRC-011-0_R1.	MR1. Each TFO, WO, or demand customer Transmission Owner and Distribution Provider that owns a UVLS system shall must have documentation that its UVLS equipment maintenance and testing program conforms with Reliability Standard PRC-011-0 <u>A written program exists and includes all the elements as identified in the sub-requirements of R1.</u>		
Requirement	R1.1. The UVLS system identification which shall include but is not limited to:	R1.1. <u>Identification identify of the UVLS system scheme and equipment identification</u> which <u>must shall</u> includes, <u>but is not limited to:</u> <ul style="list-style-type: none"> • <u>relays</u> • <u>instrument transformers</u> • <u>communications systems, where appropriate</u> • <u>batteries</u> • <u>and other equipment as required.</u> 		

**ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0
UVLS ~~System Scheme~~ Maintenance and Testing**

Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
Measure		<u>MR1.1. Ensure identified equipment is complete. (nothing missing) A written program that specifies identifies all equipment related to applicable UVLS systemschemes, as identified in requirement per R1.1.</u>		
Requirement	R1.1.1. Relays.	R1.1.1. Relays.		
Measure				
Requirement	R1.1.2. Instrument transformers.	R1.1.2. Instrument transformers.		
Measure				
Requirement	R1.1.3. Communications systems, where appropriate.	R1.1.3. Communications systems, where appropriate.		
Measure				
Requirement	R1.1.4. Batteries.	R1.1.4. Batteries.		
Measure				
Requirement	R1.2. Documentation of maintenance and testing intervals and their basis.	R1.2. have d Documentation of maintenance and testing intervals and their basis.		
Measure		<u>MR1.2 Testing intervals are identified and basis of setting intervals is specified. A written program which specifies a basis for setting testing intervals and for setting maintenance intervals.</u>		
Requirement	R1.3. Summary of testing procedure.	R1.3 have a s Summary of testing procedures.		

**ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0
UVLS ~~System Scheme~~ Maintenance and Testing**

Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
Measure		MR1.3 Testing procedures cover all equipment identified A written program specifies the test procedures for each type of equipment identified in sub- requirement R1.1.		
Requirement	R1.4. Schedule for system testing.	R1.4. H have a schedule for UVLS system scheme testing.		
Measure		MR1.4 System testing schedules are included. (and reasonable.) A written program includes system testing schedules for each UVLS systemscheme and associated equipment.		
Requirement	R1.5. Schedule for system maintenance.	R1.5. Schedule have a schedule for UVLS schemesystem maintenance.		
Measure		MR1.5. System UVLS scheme maintenance schedules are complete. A written program includes system maintenance schedules for each UVLS systemscheme and associated equipment.		
Requirement	R1.6. Date last tested/maintained.	R1.6. identify the D date last tested/maintained.		

ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0 UVLS System Scheme Maintenance and Testing				
Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
Measure		MR1.6 A record of testing and maintenance events exists, is complete and accurate. Supporting evidence of the date last tested/maintained.		
		R2. Each TFO, WO, and demand customer that owns a UVLS scheme must, as of the effective date of this reliability standard, maintain and test each UVLS scheme in accordance with its equipment maintenance and testing program.		
		MR2. All records of UVLS testing and maintenance created after the effective date of this reliability standard exist, are complete, accurate and are consistent with the equipment maintenance and testing program.		
Requirement	R2. The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).	R32. The Each TFO, WO, or and demand customer Transmission Owner and Distribution Provider that owns a UVLS systemscheme shall must provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and		

**ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0
UVLS ~~System Scheme~~ Maintenance and Testing**

Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
		testing program to its Regional Reliability Organization and NERC <u>the ISO</u> on request within 230 <u>30</u> calendar days.		
Measure	M2. Each Transmission Owner and Distribution Provider that owns a UVLS system shall have evidence it provided documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program as specified in Reliability Standard PRC-011-0_R2.	MR32. Each TFO, WO, or demand customer Transmission Owner and Distribution Provider <u>W that owns a UVLS system shall have evidence it provided documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program as specified in requirement Reliability Standard PRC-011-0_R2. Confirmation that the program was provided within the timelines specified in requirement R2.</u>		
<u>Requirement</u>	<u>R3.</u>	<u>R43. The ISO must provide documentation of UVLS equipment maintenance and testing programs, and the implementation of that UVLS equipment maintenance and testing programs to the WECC on request within 30 calendar days.</u>		
<u>Measure</u>	<u>M3.</u>	<u>MR43. Confirmation that the</u>		

**ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0
UVLS ~~System Scheme~~ Maintenance and Testing**

Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
		<p><u>program was provided within the timelines specified in requirement R3.</u></p> <p><u>M3. The ISO must have evidence it provided documentation of the UVLS equipment maintenance and testing programs and the implementation of that UVLS equipment maintenance and testing programs as specified in R3.</u></p>		
		<p>R5. The ISO must maintain a list of all UVLS schemes that apply to this reliability standard. <u>Refer to the associated information document identified in the Alberta reliability standards reference table on the AESO website.</u></p>	<p>Added a requirement for the ISO to maintain a list of relevant UVLS schemes and identified a reference to the list.</p>	
		<p>M5. A list exists that identifies all UVLS schemes as required in R5.</p>		
Procedures				
Compliance	<p>To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/PRC-011-0.pdf</p>		<p>There is no compliance section currently proposed in the Alberta Reliability</p>	

ARC Operations Work Group Assessment and Conversion of NERC PRC-011-0 to Alberta PRC-011-AB-0 UVLS <u>System Scheme</u> Maintenance and Testing				
Section	NERC PRC-011-0	Alberta PRC-011-AB-0	Reason for Difference ⁴³	Comments ⁴⁴
			Standards. A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	None identified.	None identified.	Not applicable in Alberta	



Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

- day
- Commission
- demand
- ISO
- reliability standard
- **system**
- transmission facility owner (TFO)
- under voltage load shedding (UVLS)
- wire owner (WO)
- Western Electric Coordinating Council (WECC)

Standard Owner:

Jerry Mossing, Director – Transmission Support

AESO Requirement Owner(s):

Dan Shield, Technical Specialist

AESO Subject Matter Expert(s):

Dan Shield, Technical Specialist

Work Group Comments:

None

AESO Response:

Work Group Recommendation:



The TWG members agree to recommend this standard to the ARC.

Developed by:

Name	Organization	Role
Dan Shield	AESO	TWG - Chair
Ken Gardner	AESO	Reliability Standards Technical Specialist
Peter Wong	AESO	Compliance
Mark Apuzzo	ENMAX	TWG – Team member (Preliminary review)
Raymond Wong	ATCO Electric	TWG – Team member (Preliminary review)
Peter Wang	TransAlta	TWG – Team member
Anirban Bosu	TransAlta	TWG – Team member
Elizabeth Olivier	Consultant	Technical Writer – Document Review
Larry Kram	AESO	Legal
Rob McLeod	ENMAX Generation	TWG – Team member
Mark Thompson	AESO	TWG – Team member
Dale Reso	AltaLink	TWG – Team member
Cristina Papuc	TransAlta	TWG – Team member
Blaine Beisiegel	ATCO Electric	TWG – Team member
John Walker	ATCO Power	TWG – Team member
Shamir Ladhani	ENMAX	TWG – Team member

ARC Operations Work Group Assessment and Conversion of NERC PRC-017-0 to Alberta PRC-017-AB-0 Special Protection System Remedial Action Scheme Maintenance and Testing				
Section	NERC PRC-017-0	Alberta PRC-017-AB-0	Reason for Difference ⁴⁶	Comments ⁴⁷
Purpose	To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.	The purpose of this reliability standard is to ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. <u>to ensure that maintenance and testing programs are developed for action schemes (RASs).</u>		
Applicability	<p>4.1. Transmission Owner that owns an SPS</p> <p>4.2. Generator Owner that owns an SPS</p> <p>4.3. Distribution Provider that owns an SPS</p>	<p><u>This reliability standard applies to:</u></p> <ul style="list-style-type: none"> Transmission Owner TFOs that own an SPSRAS or a component of a RAS <u>that is listed as an AB RAS in the ISO RAS database.</u> Generator Owner GFOs that own an SPSRAS or a component of a RAS <u>that is listed as an AB RAS in the ISO RAS database.</u> Distribution Provider DFOs WOs that own an SPSRAS or a component of a RAS <u>that is listed as an AB RAS in the ISO RAS database.</u> 	Identified the RAS classification that applies to this standard.	

⁴⁶ The following revisions have been made throughout this proposed reliability standard:

- Identified the responsible entities in Alberta.
- Applied a consistent writing style and added clarity.
- Changed passive terms such as “shall” to “must”.
- Developed measures specific to the requirements.

⁴⁷ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC Operations Work Group Assessment and Conversion of NERC PRC-017-0 to Alberta PRC-017-AB-0 Special Protection System Remedial Action Scheme Maintenance and Testing				
Section	NERC PRC-017-0	Alberta PRC-017-AB-0	Reason for Difference ⁴⁶	Comments ⁴⁷
		<ul style="list-style-type: none"> ISO 		
Effective Date	April 1, 2005	Ten One hundred and eighty <u>calendar days</u> after the date of approval by the <u>Commission</u> . April 1, 2005	180 calendar days to develop maintenance and testing programs.	TWG members recommend 365 calendar days to develop maintenance and testing programs and up to 2 years for documentation of full functional test results.
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules. ⁴⁸	Added definitions section to the Alberta reliability standard.	
Requirement	R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	R1 <u>Each Transmission Owner, Generator Owner, and Distribution Provider TFO, GFO, and DFOWOs</u> that own <u>se</u> a <u>SPSRAS</u> or <u>equipment integral to a RAS</u> , shall <u>must</u> have system -maintenance and testing programs in place. The <u>se</u> programs shall must include :		

⁴⁸ Defined terms are not italicized in this document, but will appear in the Alberta Reliability Standards document.

ARC Operations Work Group Assessment and Conversion of NERC PRC-017-0 to Alberta PRC-017-AB-0 Special Protection System Remedial Action Scheme Maintenance and Testing				
Section	NERC PRC-017-0	Alberta PRC-017-AB-0	Reason for Difference ⁴⁶	Comments ⁴⁷
Measure	M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0_R1.	MR1 <u>A written program exists and includes the elements as identified in sub-requirements of R1.</u> The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS <u>RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0 requirement R1.</u>		
Requirement	R1.1. SPS identification shall include but is not limited to:	R1.1 <u>identify</u> the components that make up each SPS <u>RAS must be identified</u> ation shall including, <u>but is not limited to the following:</u> <ul style="list-style-type: none"> • <u>r</u>elays • <u>i</u>nstrument transformers • <u>C</u>ommunications systems, where appropriate • <u>B</u>batteries • <u>and other equipment as required for the RAS to function</u> 		
Measure		MR1.1 <u>A written program identifies all equipment related to applicable RAS, as identified in per-requirement R1.1.</u>		
Requirement	R1.1.1. Relays.	R1.1.1. <u>Relays.</u>		
Measure				
Requirement	R1.1.2. Instrument transformers.	R1.1.2. <u>Instrument transformers.</u>		
Measure				
Requirement	R1.1.3. Communications systems, where appropriate.	R1.1.3. <u>Communications systems, where appropriate.</u>		

ARC Operations Work Group Assessment and Conversion of NERC PRC-017-0 to Alberta PRC-017-AB-0 Special Protection System Remedial Action Scheme Maintenance and Testing				
Section	NERC PRC-017-0	Alberta PRC-017-AB-0	Reason for Difference ⁴⁶	Comments ⁴⁷
Measure				
Requirement	R1.1.4. Batteries.	R1.1.4. Batteries.		
Measure				
Requirement	R1.2. Documentation of maintenance and testing intervals and their basis.	R1.2. have d Documentation of maintenance and testing intervals and their basis.		
Measure		<u>MR1.2. A written program that specifies a basis for setting testing intervals and maintenance intervals.</u>		
Requirement	R1.3. Summary of testing procedure.	R1.3. have a Summary-summary of the testing procedure.		
Measure		<u>MR1.3 A written program that specifies the test procedures for each type of equipment identified in sub-requirement, R1.1.ied.</u>		
Requirement	R1.4. Schedule for system testing.	R1.4. have a s Schedule for system testing.		
Measure		<u>MR1.4. A written program includes system testing schedules for each UVLS systemRAS and associated equipment.</u>		
Requirement	R1.5. Schedule for system maintenance.	R1.5. have a s Schedule for system maintenance.		
Measure		<u>MR1.5 System maintenance schedules are complete A written program includes system maintenance schedules for each UVLS systemRAS and associated equipment.</u>		
Requirement	R1.6. Date last tested/maintained.	R1.6. Date-identify the date last tested/maintained.		

ARC Operations Work Group Assessment and Conversion of NERC PRC-017-0 to Alberta PRC-017-AB-0 Special Protection System Remedial Action Scheme Maintenance and Testing				
Section	NERC PRC-017-0	Alberta PRC-017-AB-0	Reason for Difference ⁴⁶	Comments ⁴⁷
Measure		MR1.6 A record of testing and maintenance events exists, and is complete and accurate. Supporting evidence of the date last tested/maintained.		
		R2. Each TFO, GFO, and WO that owns a RAS or equipment integral to a RAS must, As of the effective date of this reliability standard, maintain and test each RAS or components of a RAS must be maintained and tested in accordance with the system maintenance and testing program.		
		MR2. All records of RAS testing and maintenance created after the effective date of this reliability standard exist, are complete, accurate and are consistent with the system maintenance and testing program.		
Requirement	R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	R32. The Each Transmission Owner, Generator Owner, and Distribution Provider TFO, GFO, and WODFO that owns an SPSRAS or equipment integral to a RAS mustshall each provide documentation of the RAS maintenance and testing program, and its implementation to the ISO appropriate Regional Reliability Organizations and NERC on request within 2030 calendar days.		

ARC Operations Work Group Assessment and Conversion of NERC PRC-017-0 to Alberta PRC-017-AB-0 Special Protection System Remedial Action Scheme Maintenance and Testing				
Section	NERC PRC-017-0	Alberta PRC-017-AB-0	Reason for Difference ⁴⁶	Comments ⁴⁷
Measure	M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	MR32. Confirmation that the RAS maintenance and testing program was provided with documentation of its implementation within the timelines specified in requirement R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS RAS shall have evidence it provided documentation of the RAS maintenance and testing program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).		
<u>Requirement</u>		R43. The ISO must provide documentation of the RAS maintenance and testing program and its implementation to the ISOWECC on request within 230 calendar days.		
<u>Measure</u>		MR43. Confirmation that the RAS maintenance and testing program was provided with documentation of its implementation within the timelines specified in requirement R3. RAS maintenance and testing WECC		
		R5. The ISO must maintain a list of all RASs that apply to this reliability standard. Refer to the associated information document identified in the Alberta reliability standards reference table on the AESO website.	Added a requirement for the ISO to maintain a list of relevant RASs.	
		M5. A list exists that identifies all RASs as		

ARC Operations Work Group Assessment and Conversion of NERC PRC-017-0 to Alberta PRC-017-AB-0 Special Protection System Remedial Action Scheme Maintenance and Testing				
Section	NERC PRC-017-0	Alberta PRC-017-AB-0	Reason for Difference ⁴⁶	Comments ⁴⁷
		required in R5.		
Procedures				
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/PRC-017-0.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	1. None identified.	None identified.	Not applicable in Alberta	



Proposed Terms for the ARS Glossary:

None

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

- day
- Commission
- generating facility owner (GFO)
- ISO
- reliability standard
- remedial action scheme (RAS)
- ~~system~~
- transmission facility owner (TFO)
- ~~under voltage load shedding (UVLS)~~
- wire owner (WO)
- Western Electric Coordinating Council (WECC)

Standard Owner:

Jerry Mossing, Director – Transmission Support

AESO Requirement Owner(s):

Dan Shield, Technical Specialist

AESO Subject Matter Expert(s):

Dan Shield, Technical Specialist

Work Group Comments:

TWG members have not seen the proposed RAS list and are uncertain if 180 days is sufficient time for implementation. At this time the TWG members (TransAlta, ATCO Power, ATCO Electric and AltaLink) recommend 365 calendar days to assess current records, develop maintenance and testing programs and identify gaps. Following that, 1-2 years for documentation and coordination with other entities of full functional test results.

AESO Response:

Draft: 2010-04-28 OWG recommendation to ARC (Highlighting indicates revisions since organization review)



Due to the importance of these facilities, the AESO believes a 180 day implementation is appropriate. The AESO will provide the RAS list prior to public consultation such that additional comments can be received from the TWG members based on the contents in the list.

Work Group Recommendation:

The Technical Work Group members agree to recommend PRC-017-AB-0 to the ARC. Further comments in regards to implementation date will be considered during public consultation.

Developed by:

Name	Organization	Role
Dan Shield	AESO	TWG - Chair
Ken Gardner	AESO	Reliability Standards Technical Specialist
Peter Wong	AESO	Compliance
Mark Apuzzo	ENMAX	TWG – Team member (Preliminary review)
Raymond Wong	ATCO Electric	TWG – Team member (Preliminary review)
Peter Wang	TransAlta	TWG – Team member
Anirban Bosu	TransAlta	TWG – Team member
Elizabeth Olivier	Consultant	Technical Writer – Document Review
Larry Kram	AESO	Legal



Rob McLeod	ENMAX Generation	TWG – Team member
Mark Thompson	AESO	TWG – Team member
Dale Reso	AltaLink	TWG – Team member
Cristina Papuc	TransAlta	TWG – Team member
Blaine Beisiegel	ATCO Electric	TWG – Team member
John Walker	ATCO Power	TWG – Team member
Shamir Ladhani	ENMAX	TWG – Team member

ARC Operations Work Group Assessment and Conversion of NERC IRO-004-2 to Alberta IRO-004-AB-2 Reliability Coordination Operations Planning				
Section	NERC IRO-004-2	Alberta IRO-004-AB-2	Reason for Difference	Comments ⁴⁹
Purpose	Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.	Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.	Recommend this reliability standard to be rejected for application in Alberta. The ISO will respond to WECC Reliability Coordinator directives in accordance with IRO-001-AB-1 R1.	The NERC purpose reads like requirements. The following is a suggested purpose: The purpose of this reliability standard is to address how entities are to respond to WECC Reliability Coordinator directives based on next day reliability assessments.
Applicability	4.1. Balancing Authorities. 4.2. Transmission Operators. 4.3. Transmission Service Providers.	4.1. Balancing Authorities. 4.2. Transmission Operators. 4.3. Transmission Service Providers.		
Effective Date	In those jurisdictions where no regulatory approval is required,	In those jurisdictions where no regulatory approval is required, the		

⁴⁹ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operations Work Group Assessment and Conversion of NERC IRO-004-2 to Alberta IRO-004-AB-2
Reliability Coordination Operations Planning**

Section	NERC IRO-004-2	Alberta IRO-004-AB-2	Reason for Difference	Comments ⁴⁹
	<p>the standard shall be retired on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.</p> <p>In those jurisdictions where regulatory approval is required, the standard shall be retired effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.</p>	<p>standard shall be retired on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.</p> <p>In those jurisdictions where regulatory approval is required, the standard shall be retired effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.</p>		
Definitions				
Requirement	<p>R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.</p>	<p>R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.</p>	<p>Alberta Variance: IRO-004-2 address how entities are to respond to Reliability Coordinator directives based on next day reliability assessments. IRO-001-AB-1 R1 covers all WECC Reliability Coordinator directives to the ISO and day ahead</p>	

**ARC Operations Work Group Assessment and Conversion of NERC IRO-004-2 to Alberta IRO-004-AB-2
Reliability Coordination Operations Planning**

Section	NERC IRO-004-2	Alberta IRO-004-AB-2	Reason for Difference	Comments⁴⁹
			directives from the Reliability Coordinator will be complied with accordingly.	
Measure	M1. None	M1. None		
Requirement				
Measure				
Procedures				
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/IRO-004-2.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	



**ARC Operations Work Group Assessment and Conversion of NERC IRO-004-2 to Alberta IRO-004-AB-2
Reliability Coordination Operations Planning**

Section	NERC IRO-004-2	Alberta IRO-004-AB-2	Reason for Difference	Comments⁴⁹
Regional Differences	None identified.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary:

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

Standard Owner:

Neil Curtis, Director - Grid and Market Operations

Work Group Comments:

None

Work Group Recommendation:

The Operations Work Group recommends the AESO Reliability Committee to consider this NERC reliability standard as not applicable in Alberta.

Developed by:

Name	Organization	Role
Doug Hincks	AESO	OWG Chair
Jerry Mossing	AESO	Previous OWG Chair



Name	Organization	Role
Ken Gardner	AESO	Reliability Standards Technical Specialist
Don Olson	AESO	OWG – Team member (preliminary review)
John Walker	ATCO Power	OWG – Team member (preliminary review)
Dwayne Aasberg	Dow Chemical	OWG – Team member
Terri Haffick	ENMAX	OWG – Team member (preliminary review)
Anirban Bosu	TransAlta	OWG – Team member
Dan Bamber	TransAlta	OWG – Team member
Blaine Beisiegel	ATCO Electric	OWG – Team member
Rick Spyker	AltaLink	OWG – Team member
Kevin Neithercut	ENMAX	OWG – Team member (preliminary review)
Mark Thompson	AESO	OWG – Team member (preliminary review)
Michael Taylor	Capital Power	OWG – Team member
Neil Curtis	AESO	OWG – Alternate Chair
Stew Purkis	City of Lethbridge	OWG – Team member
Chris Best	TransCanada	OWG – Team member
Gerry Young	Suncor	OWG – Team member
Roy Hanson	ENMAX CEC	OWG – Team member
Cal Lenz	ATCO Power	OWG – Team member
Subrota Bairgi	Suncor	OWG – Team member
Amber Kirby	Capital Power	OWG – Team member
Blaise Smith	TransAlta	OWG – Team member



Name	Organization	Role
Penny Haldane	ENMAX	OWG – Team member
Ron Smith	AESO	OWG member
Peter Tam	AESO	OWG member
Ravinder Farwaha	Suncor	OWG member
Dan Bamber	TransAlta	OWG member
Dwayne Aasberg	Dow Chemical	OWG member
Michael Taylor	Capital Power Corp.	OWG member

ARC Operation Work Group Assessment and Conversion of NERC MOD-011-0 to Alberta MOD-011-AB-0 Regional Steady-State Data Requirements and Reporting Procedures				
Section	NERC MOD-011-0	Alberta MOD-011-AB-0	Reason for Difference	Comments ⁵⁰
Purpose	To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems	To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems	This reliability standard is not applicable in Alberta. It requires the WECC to jointly establish data requirements with Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners	
Applicability	4.1. Regional Reliability Organization	4.1. Regional Reliability Organization		
Effective Date	April 1, 2005	April 1, 2005		
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.		
Requirement	R1. The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data	R1. The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall		

⁵⁰ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC Operation Work Group Assessment and Conversion of NERC MOD-011-0 to Alberta MOD-011-AB-0 Regional Steady-State Data Requirements and Reporting Procedures

Section	NERC MOD-011-0	Alberta MOD-011-AB-0	Reason for Difference	Comments ⁵⁰
	<p>requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:</p>	<p>develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:</p>		
Measure				
Requirement	<p>R1.1. Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0), and location.</p>	<p>R1.1. Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0), and</p>		

ARC Operation Work Group Assessment and Conversion of NERC MOD-011-0 to Alberta MOD-011-AB-0 Regional Steady-State Data Requirements and Reporting Procedures				
Section	NERC MOD-011-0	Alberta MOD-011-AB-0	Reason for Difference	Comments ⁵⁰
		location.		
Measure				
Requirement	R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status.	R1.2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status.		
Measure				
Requirement	R1.3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0) equipment status, and metering locations.	R1.3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0) equipment status, and metering locations.		
Measure				
Requirement	R1.4. DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and	R1.4. DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control		

ARC Operation Work Group Assessment and Conversion of NERC MOD-011-0 to Alberta MOD-011-AB-0 Regional Steady-State Data Requirements and Reporting Procedures				
Section	NERC MOD-011-0	Alberta MOD-011-AB-0	Reason for Difference	Comments ⁵⁰
	inverter data.	parameters, rectifier data, and inverter data.		
Measure				
Requirement	R1.5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0.), and equipment status.	R1.5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0.), and equipment status.		
Measure				
Requirement	R1.6. Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device.	R1.6. Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device.		
Measure				
Requirement	R1.7. Interchange Schedules: Existing and future Interchange Schedules and/or assumptions.	R1.7. Interchange Schedules: Existing and future Interchange Schedules and/or assumptions.		

ARC Operation Work Group Assessment and Conversion of NERC MOD-011-0 to Alberta MOD-011-AB-0 Regional Steady-State Data Requirements and Reporting Procedures				
Section	NERC MOD-011-0	Alberta MOD-011-AB-0	Reason for Difference	Comments ⁵⁰
Measure				
Requirement	<p>R2. The Regional Reliability Organizations within an Interconnection shall document their Interconnection’s steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.</p>	<p>R2. The Regional Reliability Organizations within an Interconnection shall document their Interconnection’s steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.</p>		
Measure	<p>M1. The Regional Reliability Organization shall have documentation of its Interconnection’s steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-011-0_R2.</p>	<p>M1. The Regional Reliability Organization shall have documentation of its Interconnection’s steady-state data requirements and reporting procedures and shall provide the documentation as specified in Reliability Standard MOD-011-0_R2.</p>		
Procedures				

ARC Operation Work Group Assessment and Conversion of NERC MOD-011-0 to Alberta MOD-011-AB-0 Regional Steady-State Data Requirements and Reporting Procedures

Section	NERC MOD-011-0	Alberta MOD-011-AB-0	Reason for Difference	Comments⁵⁰
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/MOD-011-0.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	None identified.		Not applicable in Alberta	



Proposed Terms for the ARS Glossary:

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

Standard Owner:

Jerry Mossing, Director - Transmission Support

AESO Requirement Owner(s):

AESO Subject Matter Expert(s):

Pamela Mclean, Technical Lead – Power System Model Management

Work Group Comments:

None

Work Group Recommendation:

The Operations Work Group recommends the AESO Reliability Committee to consider this NERC reliability standard as not applicable in Alberta.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	Standard Owner
Pamela Mclean	AESO	Subject Matter Expert



Name	Organization	Role
Doug Hincks	AESO	OWG Chair
Ken Gardner	AESO	Reliability Standards Technical Specialist
Don Olson	AESO	OWG – Team member (preliminary review)
John Walker	ATCO Power	OWG – Team member (preliminary review)
Dwayne Aasberg	Dow Chemical	OWG – Team member
Terri Haffick	ENMAX	OWG – Team member (preliminary review)
Anirban Bosu	TransAlta	OWG – Team member
Dan Bamber	TransAlta	OWG – Team member
Blaine Beisiegel	ATCO Electric	OWG – Team member
Rick Spyker	AltaLink	OWG – Team member
Kevin Neithercut	ENMAX	OWG – Team member (preliminary review)
Mark Thompson	AESO	OWG – Team member (preliminary review)
Michael Taylor	Capital Power	OWG – Team member
Neil Curtis	AESO	OWG – Alternate Chair
Stew Purkis	City of Lethbridge	OWG – Team member
Chris Best	TransCanada	OWG – Team member
Gerry Young	Suncor	OWG – Team member
Roy Hanson	ENMAX CEC	OWG – Team member
Cal Lenz	ATCO Power	OWG – Team member
Subrota Bairgi	Suncor	OWG – Team member
Amber Kirby	Capital Power	OWG – Team member



Name	Organization	Role
Blaise Smith	TransAlta	OWG – Team member
Penny Haldane	ENMAX	OWG – Team member

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
Purpose	To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.	To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.	This reliability standard is assessed as not applicable in Alberta. The rated path methodology as described in MOD-029-AB will be applied in Alberta for determining available transfer capability on ATC paths.	
Applicability	<p>4.1. Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.</p> <p>4.2. Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.</p>	<p>4.1. Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.</p> <p>4.2. Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.</p>		
Effective Date	First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.	First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved by all applicable regulatory authorities.		
Definitions		Italicized terms used in this reliability		

⁵¹ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
		standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.⁵²		
Requirement	R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): <i>[Violation Risk Factor: Lower]</i> <i>[Time Horizon: Operations Planning]</i>	R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): <i>[Violation Risk Factor: Lower]</i> <i>[Time Horizon: Operations Planning]</i>		
Measure	M1. Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)	M1. Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)		
Requirement	R1.1. Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.	R1.1. Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.		
Measure				
Requirement	R1.2. A description of the manner in which the Transmission Operator will account for Interchange Schedules in the	R1.2. A description of the manner in which the Transmission Operator will account for Interchange Schedules in the		

⁵² Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
	calculation of TTC.	calculation of TTC.		
Measure				
Requirement	R1.3. Any contractual obligations for allocation of TTC.	R1.3. Any contractual obligations for allocation of TTC.		
Measure				
Requirement	R1.4. A description of the manner in which Contingencies are identified for use in the TTC process.	R1.4. A description of the manner in which Contingencies are identified for use in the TTC process.		
Measure				
Requirement	R1.5. The following information on how source and sink for transmission service is accounted for in ATC calculations including:	R1.5. The following information on how source and sink for transmission service is accounted for in ATC calculations including:		
Measure				
Requirement	R1.5. 1. Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation	R1.5. 1. Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation		
Measure				
Requirement	R1.5. 2. Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation	R1.5. 2. Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation		
Measure				
Requirement	R1.5. 3. The source/sink or POR/POD identification and mapping to the model.	R1.5. 3. The source/sink or POR/POD identification and mapping to the model.		

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
Measure				
Requirement	R1.5. 4. If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.	R1.5. 4. If the Transmission Service Provider's ATC calculation process involves a grouping of generation, the ATCID must identify how these generators participate in the group.		
Measure				
Requirement	R2. When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>	R2. When calculating TTC for ATC Paths, the Transmission Operator shall use a Transmission model that contains all of the following: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>		
Measure	M2. Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)	M2. Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)		
Requirement	R2.1. Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.	R2.1. Modeling data and topology of its Reliability Coordinator's area of responsibility. Equivalent representation of radial lines and facilities 161 kV or below is allowed.		
Measure				
Requirement	R2.2. Modeling data and topology (or	R2.2. Modeling data and topology (or		

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
	equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.	equivalent representation) for immediately adjacent and beyond Reliability Coordination areas.		
Measure				
Requirement	R2.3. Facility Ratings specified by the Generator Owners and Transmission Owners.	R2.3. Facility Ratings specified by the Generator Owners and Transmission Owners.		
Measure				
Requirement	R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]	R3. When calculating TTCs for ATC Paths, the Transmission Operator shall include the following data for the Transmission Service Provider's area. The Transmission Operator shall also include the following data associated with Facilities that are explicitly represented in the Transmission model, as provided by adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]		

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
Measure	M3. Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)	M3. Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)		
Requirement	R3.1. For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):	R3.1. For on-peak and off-peak intra-day and next-day TTCs, use the following (as well as any other values and additional parameters as specified in the ATCID):		
Measure				
Requirement	R3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.	R3.1.1. Expected generation and Transmission outages, additions, and retirements, included as specified in the ATCID.		
Measure				
Requirement	R3.1.2. Load forecast for the applicable period being calculated.	R3.1.2. Load forecast for the applicable period being calculated.		
Measure				
Requirement	R3.1.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.	R3.1.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.		

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
Measure				
Requirement	R3.2. For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):	R3.2. For days two through 31 TTCs and for months two through 13 TTCs, use the following (as well as any other values and internal parameters as specified in the ATCID):		
Measure				
Requirement	R3.2.1. Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.	R3.2.1. Expected generation and Transmission outages, additions, and Retirements, included as specified in the ATCID.		
Measure				
Requirement	R3.2.2. Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.	R3.2.2. Daily load forecast for the days two through 31 TTCs being calculated and monthly forecast for months two through 13 months TTCs being calculated.		
Measure				
Requirement	R3.2.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.	R3.2.3. Unit commitment and dispatch order, to include all designated network resources and other resources that are committed or have the legal obligation to run, (within or out of economic dispatch) as they are expected to run.		
Measure				
Requirement	R4. When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions:	R4. When calculating TTCs for ATC Paths, the Transmission Operator shall meet all of the following conditions:		

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Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
	<i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>	<i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>		
Measure	M4. Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)	M4. Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)		
Requirement	R4.1. Use all Contingencies meeting the criteria described in the ATCID.	R4.1. Use all Contingencies meeting the criteria described in the ATCID.		
Measure				
Requirement	R4.2. Respect any contractual allocations of TTC.	R4.2. Respect any contractual allocations of TTC.		
Measure	M5. Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)	M5. Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)		
Requirement	R4.3. Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers,	R4.3. Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers,		

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
	<p>and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:</p> <ul style="list-style-type: none"> – If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source. – If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source. – If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an “equivalence,” or an “aggregate 	<p>and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:</p> <ul style="list-style-type: none"> –If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source. –If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source. –If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission 		

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	<p>representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.</p> <ul style="list-style-type: none"> – If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source. – If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point shall as the sink. – If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate 	<p>Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.</p> <p>–If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.</p> <p>–If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point shall as the sink.</p> <p>–If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission</p>		

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Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
	<p>representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.</p> <ul style="list-style-type: none"> – If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink. – If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink. 	<p>Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.</p> <p>–If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.</p> <p>– If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.</p>		

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Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
Measure	M6. Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)	M6. Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)		
Requirement	R5. Each Transmission Operator shall establish TTC for each ATC Path as defined below: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>	R5. Each Transmission Operator shall establish TTC for each ATC Path as defined below: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>		

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Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
Measure	M7. Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)	M7. Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)		
Requirement	R5.1. At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.	R5.1. At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.		
Measure				
Requirement	R5.2. At least once per calendar month for TTCs used in monthly ATC calculations.	R5.2. At least once per calendar month for TTCs used in monthly ATC calculations.		

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Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
Measure				
Requirement	R5.3. Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.	R5.3. Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.		
Measure				
Requirement	R6. Each Transmission Operator shall establish TTC for each ATC Path using the following process: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>	R6. Each Transmission Operator shall establish TTC for each ATC Path using the following process: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>		
Measure	M8. Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)	M8. Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)		
Requirement	R6.1. Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: – A System Operating Limit is reached	R6.1. Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: – A System Operating Limit is reached on		

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	<p>on the Transmission Service Provider's system, or</p> <ul style="list-style-type: none"> A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater¹. 	<p>the Transmission Service Provider's system, or</p> <ul style="list-style-type: none"> A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater⁴. 		
Measure				
Requirement	<p>R6.2. If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.</p>	<p>R6.2. If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.</p>		
Measure				
Requirement	<p>R6.3. Use (as the TTC) the lesser of:</p> <ul style="list-style-type: none"> The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or The sum of Facility Ratings of all ties comprising the ATC Path. 	<p>R6.3. Use (as the TTC) the lesser of:</p> <ul style="list-style-type: none"> The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider's ATCID, that were included in the study model, or The sum of Facility Ratings of all ties comprising the ATC Path. 		

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Measure				
Requirement	R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.	R6.4. For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider's contractual rights.		
Measure				
Requirement	R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>	R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>		
Measure	M9. Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)	M9. Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)		
Requirement	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations.	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations.		
Measure				
Requirement	R7.2. Seven calendar days after its	R7.2. Seven calendar days after its		

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	determination for TTCs used in monthly ATC calculations.	determination for TTCs used in monthly ATC calculations.		
Measure				
Requirement	<p>R8. When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i></p> $ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$ <p>Where: $NITS_F$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities. GF_F is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed</p>	<p>R8. When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i></p> $ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$ <p>Where: $NITS_F$ is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities. GF_F is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a</p>		

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	<p>prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.</p> <p>PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.</p> <p>ROR_F is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.</p> <p>OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including another firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.</p>	<p>Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.</p> <p>PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.</p> <p>ROR_F is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.</p> <p>OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including another firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.</p>		

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Measure	<p>M10. The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)</p>	<p>M10. The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)</p>		
Requirement	<p>R9. When calculating ETC for non-firm commitments (ETC_{NF}) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] $ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$ Where:</p>	<p>R9. When calculating ETC for non-firm commitments (ETC_{NF}) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning] $ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$ Where:</p>		

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	<p>NITS_{NF} is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider’s area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.</p> <p>GF_{NF} is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.</p> <p>PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.</p> <p>OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect</p>	<p>NITS_{NF} is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service , including the capacity used to serve bundled load within the Transmission Service Provider’s area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.</p> <p>GF_{NF} is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.</p> <p>PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.</p> <p>OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect</p>		

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	impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.	impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.		
Measure	M11. The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)	M11. The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)		
Requirement	R10. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>	R10. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>		

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	<p>$ATC_F = TTC - ETC_F - CBM - TRM +$ $Postbacks_F + counterflows_F$</p> <p>Where: ATC_F is the firm Available Transfer Capability for the ATC Path for that period. TTC is the Total Transfer Capability of the ATC Path for that period. ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period. CBM is the Capacity Benefit Margin for the ATC Path during that period. TRM is the Transmission Reliability Margin for the ATC Path during that period. Postbacks_F are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices. counterflows_F are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.</p>	<p>$ATC_F = TTC - ETC_F - CBM - TRM +$ $Postbacks_F + counterflows_F$</p> <p>Where: ATC_F is the firm Available Transfer Capability for the ATC Path for that period. TTC is the Total Transfer Capability of the ATC Path for that period. ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period. CBM is the Capacity Benefit Margin for the ATC Path during that period. TRM is the Transmission Reliability Margin for the ATC Path during that period. Postbacks_F are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices. counterflows_F are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.</p>		

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Measure	<p>M12. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)</p>	<p>M12. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)</p>		
Requirement	<p>R11. When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i></p> $ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$ <p>Where:</p>	<p>R11. When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i></p> $ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$ <p>Where:</p>		

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
	<p>ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.</p> <p>TTC is the Total Transfer Capability of the ATC Path for that period.</p> <p>ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.</p> <p>ETC_{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.</p> <p>CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.</p> <p>TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.</p> <p>Postbacks_{NF} are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.</p> <p>counterflows_{NF} are adjustments to non-firm ATC as determined by the</p>	<p>ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.</p> <p>TTC is the Total Transfer Capability of the ATC Path for that period.</p> <p>ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.</p> <p>ETC_{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.</p> <p>CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.</p> <p>TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.</p> <p>Postbacks_{NF} are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.</p> <p>counterflows_{NF} are adjustments to non-firm ATC as determined by the</p>		

ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
	Transmission Service Provider and specified in the ATCID.	Transmission Service Provider and specified in the ATCID.		
Measure	M13. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)	M13. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)		
Procedures				
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/MOD-028-1.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. A compliance program will be developed at a later date	



ARC Operation Work Group Assessment and Conversion of NERC MOD-028-1 to Alberta MOD-028-AB-1 — Area Interchange Methodology				
Section	NERC MOD-028-1	Alberta MOD-028-AB-1	Reason for Difference	Comments ⁵¹
			<p>for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta.</p> <p>This approach is deemed consistent with the existing ISO Rules.</p>	
Regional Differences	None identified.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary:

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

Standard Owner:

Jerry Mossing, Director – Transmission Support

Work Group Comments:

None



Work Group Recommendation:

The Operations Work Group recommends the AESO Reliability Committee to consider this NERC reliability standard as not applicable in Alberta.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	Standard Owner
Doug Hincks	AESO	OWG Chair
Ken Gardner	AESO	Reliability Standards Technical Specialist
Don Olson	AESO	OWG – Team member (preliminary review)
John Walker	ATCO Power	OWG – Team member (preliminary review)
Dwayne Aasberg	Dow Chemical	OWG – Team member
Terri Haffick	ENMAX	OWG – Team member (preliminary review)
Anirban Bosu	TransAlta	OWG – Team member
Dan Bamber	TransAlta	OWG – Team member
Blaine Beisiegel	ATCO Electric	OWG – Team member
Rick Spyker	AltaLink	OWG – Team member
Kevin Neithercut	ENMAX	OWG – Team member (preliminary review)
Mark Thompson	AESO	OWG – Team member (preliminary review)
Michael Taylor	Capital Power	OWG – Team member



Name	Organization	Role
Neil Curtis	AESO	OWG – Alternate Chair
Stew Purkis	City of Lethbridge	OWG – Team member
Chris Best	TransCanada	OWG – Team member
Gerry Young	Suncor	OWG – Team member
Roy Hanson	ENMAX CEC	OWG – Team member
Cal Lenz	ATCO Power	OWG – Team member
Subrota Bairgi	Suncor	OWG – Team member
Amber Kirby	Capital Power	OWG – Team member
Blaise Smith	TransAlta	OWG – Team member
Penny Haldane	ENMAX	OWG – Team member

ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1 Flowgate Methodology				
Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Purpose	To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.	To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.	This reliability standard is assessed as not applicable in Alberta. The rated path methodology as described in MOD-029-AB will be applied in Alberta for determining available transfer capability on ATC paths.	
Applicability	<p>4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.</p> <p>4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.</p>	<p>4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.</p> <p>4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.</p>		
Effective Date	First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities.	First day of the first calendar quarter that is twelve months beyond the date that all four standards (MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-1) are approved by all applicable regulatory authorities.		

⁵³ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1
Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Definitions		Italicized terms used in this reliability standard have the same meanings as set out in the Alberta Reliability Standards Glossary of Terms and Part 1 of the ISO Rules.⁵⁴		
Requirement	R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID). [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]	R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID). [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]		
Measure	M1. Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)	M1. Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)		
Requirement	R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability	R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered		

⁵⁴ Defined terms are not italicized in this document, but will appear in the final Alberta Reliability Standards document that is filed with the AUC.

ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1 Flowgate Methodology				
Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	(AFC) calculations.	in Available Flowgate Capability (AFC) calculations.		
Measure				
Requirement	R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:	R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:		
Measure				
Requirement	R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.	R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.		
Measure				
Requirement	R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.	R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.		
Measure				
Requirement	R1.2.3. The source/sink or POR/POD identification and mapping to the model.	R1.2.3. The source/sink or POR/POD identification and mapping to the model.		
Measure				
Requirement	R1.2.4. If the Transmission Service Provider's AFC calculation process involves a grouping of generators, the ATCID must	R1.2.4. If the Transmission Service Provider's AFC calculation process involves a grouping of generators,		

**ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1
Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
	identify how these generators participate in the group.	the ATCID must identify how these generators participate in the group.		
Measure				
Requirement	R2. The Transmission Operator shall perform the following: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]	R2. The Transmission Operator shall perform the following: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]		
Measure				
Requirement	R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:	R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:		
Measure	M2. The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)	M2. The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)		
Requirement	R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as Flowgates.	R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator's system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator's system are included as		

**ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1
Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Measure		Flowgates.		
Requirement	2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.	2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.		
Measure				
Requirement	2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.	2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.		
Measure				
Requirement	R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.	R2.1.2. Results of a first Contingency transfer analyses from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent		

**ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1
Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
		Balancing Authorities is accounted for using another ATC methodology.		
Measure				
Requirement	2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.	2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Special Protection Systems.		
Measure				
Requirement	2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.	2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.		
Measure				
Requirement	R2.1.3. Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology.	R2.1.3. Any limiting Element/Contingency combination at least within the Transmission model identified in R3.4 and R3.5 that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology.		
Measure				
Requirement	R2.1.4. Any limiting Element/Contingency	R2.1.4. Any limiting		

**ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1
Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	<p>combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:</p>	<p>Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:</p>		
Measure				
Requirement	<p>2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and</p> <ul style="list-style-type: none"> – Any generator within the Transmission Service Provider’s area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or – A transfer from any Balancing Area within the Transmission Service Provider’s area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate. – The Transmission Operator may utilize distribution factors less than 5% if desired. 	<p>2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and</p> <ul style="list-style-type: none"> – Any generator within the Transmission Service Provider’s area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or – A transfer from any Balancing Area within the Transmission Service Provider’s area to a Balancing Area adjacent has at least a 5% PTDF or OTDF impact on the Flowgate. – The Transmission Operator may 		

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Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
		utilize distribution factors less than 5% if desired.		
Measure				
Requirement	2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.	2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.		
Measure				
Requirement	R2.2. At a minimum, establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.	R2.2. At a minimum, establish the list of Flowgates to create, modify, or delete internal Flowgates definitions at least once per calendar year.		
Measure	M3. The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)	M3. The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)		
Requirement	R2.3. At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.	R2.3. At a minimum, establish the list of Flowgates to create, modify, or delete external Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.		

**ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1
Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
Measure	M4. The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)	M4. The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)		
Requirement	R2.4. Establish the TFC of each of the defined Flowgates as equal to: – For thermal limits, the System Operating Limit (SOL) of the Flowgate. – For voltage or stability limits, the flow that will respect the SOL of the Flowgate.	R2.4. Establish the TFC of each of the defined Flowgates as equal to: – For thermal limits, the System Operating Limit (SOL) of the Flowgate. – For voltage or stability limits, the flow that will respect the SOL of the Flowgate.		
Measure	M6. The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)	M6. The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)		
Requirement	R2.5. At a minimum, establish the TFC once per calendar year.	R2.5. At a minimum, establish the TFC once per calendar year.		
Measure	M6. The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)	M6. The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)		
Requirement	R2.5.1. If notified of a change in the Rating by the Transmission Owner that would affect	R2.5.1. If notified of a change in the Rating by the Transmission Owner		

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Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
	the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.	that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.		
Measure				
Requirement	R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.		
Measure	M7. The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)	M7. The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)		
Requirement	R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]	R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]		

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Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
Measure	M8. The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)	M8.The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)		
Requirement	R3.1. Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.	R3.1. Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.		
Measure				
Requirement	R3.2. Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.	R3.2. Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.		
Measure				
Requirement	R3.3. Updated at least once per month for AFC calculations for months two through 13.	R3.3. Updated at least once per month for AFC calculations for months two through 13.		
Measure				
Requirement	R3.4. Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.	R3.4. Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.		

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Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Measure				
Requirement	<p>R3.5. Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.</p>	<p>R3.5. Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.</p>		
Measure				
Requirement	<p>R4. When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]</p> <ul style="list-style-type: none"> – If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source. – If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source. – If the source, as specified in the ATCID, 	<p>R4. When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]</p> <ul style="list-style-type: none"> – If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source. – If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the 		

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Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	<p>has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.</p> <ul style="list-style-type: none"> – If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source. – If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the sink. – If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled 	<p>modeled equivalence or aggregate as the source.</p> <ul style="list-style-type: none"> – If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source. – If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source. – If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission 		

**ARC Operation Work Group Assessment and Conversion of NERC MOD-030-1 to Alberta MOD-030-AB-1
Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	<p>equivalence or aggregate as the sink.</p> <ul style="list-style-type: none"> - If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink. - If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink. 	<p>Service Provider’s Transmission model, use the discretely modeled point as the sink.</p> <p>- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate” representation in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.</p> <p>- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an “equivalence” representation in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.</p> <p>- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately</p>		

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Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
		adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.		
Measure	M9. The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)	M9. The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)		
Requirement	R5. When calculating AFCs, the Transmission Service Provider shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]	R5. When calculating AFCs, the Transmission Service Provider shall: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]		
Measure				
Requirement	R5.1. Use the models provided by the Transmission Operator.	R5.1. Use the models provided by the Transmission Operator.		
Measure	M10. The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)	M10. The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)		
Requirement	R5.2. Include in the transmission model expected generation and Transmission	R5.2. Include in the transmission model expected generation and		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.	Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.		
Measure	M11. The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)	M11. The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)		
Requirement	R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.	R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
Measure	M12. The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)	M12. The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)		
Requirement	R6. When calculating the impact of ETC for firm commitments (ETC _{Fi}) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]	R6. When calculating the impact of ETC for firm commitments (ETC_{Fi}) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]		
Measure				
Requirement	R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:	R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:		
Measure				
Requirement	R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load	R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Measure				
Requirement	R6.1.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.	R6.1.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.		
Measure				
Requirement	R6.2. The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage ¹ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.	R6.2. The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage¹ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:.		
Measure				
Requirement	R6.2.1. Load forecast for the time period being calculated, including Native Load and	R6.2.1. Load forecast for the time period being calculated, including		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
	Network Service load	Native Load and Network Service load		
Measure				
Requirement	R6.2.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.	R6.2.2. Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.		
Measure				
Requirement	R6.3. The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.	R6.3. The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.		
Measure				
Requirement	R6.4. The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a	R6.4. The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	distribution factor equal to or greater than the percentage ² used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.	for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage² used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.		
Measure				
Requirement	R6.5. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.	R6.5. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.		
Measure				
Requirement	R6.6. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage ³ used to curtail in the Interconnection-wide congestion	R6.6. The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage³ used to curtail		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.	in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.		
Measure				
Requirement	R6.7. The impact of other firm services determined by the Transmission Service Provider.	R6.7. The impact of other firm services determined by the Transmission Service Provider.		
Measure				
Requirement	R7. When calculating the impact of ETC for non-firm commitments (ETC _{NFI}) for all time periods for a Flowgate the Transmission Service Provider shall sum: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]	R7. When calculating the impact of ETC for non-firm commitments (ETC_{NFI}) for all time periods for a Flowgate the Transmission Service Provider shall sum: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Measure	<p>M14. The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)</p>	<p>M14. The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)</p>		
Requirement	<p>R7.1. The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.</p>	<p>R7.1. The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider's area.</p>		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Measure				
Requirement	<p>R7.2. The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor⁴ equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.</p>	<p>R7.2. The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor⁴ equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.</p>		
Measure				
Requirement	<p>R7.3. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.</p>	<p>R7.3. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.</p>		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Measure				
Requirement	<p>R7.4. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the ⁵ percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.</p>	<p>R7.4. The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.</p>		
Measure				
Requirement	<p>R7.5. The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.</p>	<p>R7.5. The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider's area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.</p>		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
Measure				
Requirement	R7.6. The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage ⁶ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.	R7.6. The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage⁶ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.		
Measure				
Requirement	R7.7. The impact of other non-firm services determined by the Transmission Service Provider.	R7.7. The impact of other non-firm services determined by the Transmission Service Provider.		
Measure				
Requirement	R8. When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation	R8. When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	<p>processes described in the ATCID): [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</p> $AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + \text{Postbacks}_{Fi} + \text{counterflows}_{Fi}$ <p>Where:</p> <p>AFC_F is the firm Available Flowgate Capability for the Flowgate for that period.</p> <p>TFC is the Total Flowgate Capability of the Flowgate.</p> <p>ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.</p> <p>CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.</p> <p>TRM_i is the impact of the Transmission Reliability Margin on the Flowgate during that period.</p> <p>Postbacks_{Fi} are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.</p>	<p>to-allocation processes described in the ATCID): [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</p> $AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + \text{Postbacks}_{Fi} + \text{counterflows}_{Fi}$ <p>Where:</p> <p>AFC_F is the firm Available Flowgate Capability for the Flowgate for that period.</p> <p>TFC is the Total Flowgate Capability of the Flowgate.</p> <p>ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.</p> <p>CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.</p> <p>TRM_i is the impact of the Transmission Reliability Margin on the Flowgate during that period.</p> <p>Postbacks_{Fi} are changes to firm</p>		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	<p>counterflows_{Fi} are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.</p>	<p>AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices. counterflows_{Fi} are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.</p>		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Measure	<p>M15. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)</p>	<p>M15. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)</p>		
Requirement	<p>R9. When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [Violation Risk Factor: Lower] [Time Horizon:</p>	<p>R9. When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [Violation</p>		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
	<p><i>Operations Planning]</i></p> $AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + \text{Postbacks}_{NFi} + \text{counterflows}$ <p>Where: AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period. TFC is the Total Flowgate Capability of the Flowgate. ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period. ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate durin CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin. TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period. Postbacks_{NF} are changes to non-firm Available Flowgate Capability due to a</p>	<p><i>Risk Factor: Lower] [Time Horizon: Operations-Planning]</i></p> $AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + \text{Postbacks}_{NFi} + \text{counterflows}$ <p>Where: AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period. TFC is the Total Flowgate Capability of the Flowgate. ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period. ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate durin CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin. TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released</p> 		

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	<p>change in the use of Transmission Service for that period, as defined in Business Practices.</p> <p>counterflows_{NF} are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.</p>	<p>(unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.</p> <p>Postbacks_{NF} are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.</p> <p>counterflows_{NF} are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.</p>		

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Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments ⁵³
Measure	<p>M16. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)</p>	<p>M16. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)</p>		
Requirement	<p>R10. Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have</p>	<p>R10. Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values</p>		

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	changed: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]	identified in the AFC equation have changed: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]		
Measure	M17. The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)	M17. The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)		
Requirement	R10.1 For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.	R10.1 For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.		
Measure				
Requirement	R10.2. For daily AFC, once per day.	R10.2. For daily AFC, once per day.		
Measure				
Requirement	R10.3. For monthly AFC, once per week.	R10.3. For monthly AFC, once per week.		
Measure				
Requirement	R11. When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those values based on the following	R11. When converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, the Transmission Service Provider shall convert those		

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	<p>algorithm: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]</p> $TC = \min(P)$ $P = \{PTC_1, PTC_2, \dots, PTC_n\}$ $PTC_n = n\%DFFC$ <p>Where: TC is the Transfer Capability (either 'Available' or 'Total'). P is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage₇ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF F PTC_n is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate <i>n</i>.</p>	<p>values based on the following algorithm: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]</p> $TC = \min(P)$ $P = \{PTC_1, PTC_2, \dots, PTC_n\}$ $PTC_n = n\%DFFC$ <p>Where: TC is the Transfer Capability (either 'Available' or 'Total'). P is the set of partial Transfer Capabilities (either available or total) for all "impacted" Flowgates honored by the Transmission Service Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage₇ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF F</p>		

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	<p>FC_n is the Flowgate Capability ('Available' or 'Total') of a Flowgate <i>n</i>.</p> <p>DF_{np} is the distribution factor for Flowgate <i>n</i> relative to path <i>p</i>.</p>	<p>PTC_n is the partial Transfer Capability (either 'Available' or 'Total') for a path relative to a Flowgate <i>n</i>.</p> <p>FC_n is the Flowgate Capability ('Available' or 'Total') of a Flowgate <i>n</i>.</p> <p>DF_{np} is the distribution factor for Flowgate <i>n</i> relative to path <i>p</i>.</p>		
Measure	<p>M18. The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it follows the procedure described in R11. (R11)</p>	<p>M18. The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs (and TFCs to TTCs) for ATC Paths, it follows the procedure described in R11. (R11)</p>		
Procedures				
Compliance	<p>To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/MOD-030-1.pdf</p>		<p>There is no compliance section currently proposed in the Alberta Reliability Standards.</p> <p>A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the</p>	



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Flowgate Methodology**

Section	NERC MOD-030-1	Alberta MOD-030-AB-1	Reason for Difference	Comments⁵³
			compliance monitoring and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	None identified.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary:

Existing Defined Terms Used in this Standard:

(As included in the ISO Rules Definitions or Alberta Reliability Standards Glossary)

Standard Owner:

Jerry Mossing, Director – Transmission Support

Work Group Comments:

None



Work Group Recommendation:

The Operations Work Group recommends the AESO Reliability Committee to consider this NERC reliability standard as not applicable in Alberta.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	Standard Owner
Doug Hincks	AESO	OWG Chair
Ken Gardner	AESO	Reliability Standards Technical Specialist
Don Olson	AESO	OWG – Team member (preliminary review)
John Walker	ATCO Power	OWG – Team member (preliminary review)
Dwayne Aasberg	Dow Chemical	OWG – Team member
Terri Haffick	ENMAX	OWG – Team member (preliminary review)
Anirban Bosu	TransAlta	OWG – Team member
Dan Bamber	TransAlta	OWG – Team member
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Rick Spyker	AltaLink	OWG – Team member
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Neil Curtis	AESO	OWG – Alternate Chair
Stew Purkis	City of Lethbridge	OWG – Team member



Name	Organization	Role
Chris Best	TransCanada	OWG – Team member
Gerry Young	Suncor	OWG – Team member
Roy Hanson	ENMAX CEC	OWG – Team member
Cal Lenz	ATCO Power	OWG – Team member
Subrota Bairgi	Suncor	OWG – Team member
Amber Kirby	Capital Power	OWG – Team member
Blaise Smith	TransAlta	OWG – Team member
Penny Haldane	ENMAX	OWG – Team member

ARC Operations Work Group Assessment and Conversion of NERC PER-002-0 to Alberta Standard PER-002-AB-0 Operating Personnel Training				
Section	NERC PER-002-0	Alberta PER-002-AB-0	Reason for Difference	Comments ⁵⁵
Purpose	Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation	Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.	It is recommended that PER-002-0 be rejected for application in Alberta with the development of PER-005-AB-1. This is consistent with the NERC Board of Trustees recommendation.	
Applicability	4.1. Balancing Authority. 4.2. Transmission Operator.	4.1. Balancing Authority. 4.2. Transmission Operator.		
Effective Date	April 1, 2005	April 1, 2005		
Definitions				
Requirement	R1. Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.	R1. Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.		
Measure				
Requirement	R2. Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:	R2. Each Transmission Operator and Balancing Authority shall have a training program for all operating		

⁵⁵ Including the identification of issues, compliance ideas and identification of exempt entities.

**ARC Operations Work Group Assessment and Conversion of NERC PER-002-0 to Alberta Standard PER-002-AB-0
Operating Personnel Training**

Section	NERC PER-002-0	Alberta PER-002-AB-0	Reason for Difference	Comments ⁵⁵
Measure		personnel that are in:		
Requirement	R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.	R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.		
Measure				
Requirement	R2.2. Positions directly responsible for complying with NERC standards.	R2.2. Positions directly responsible for complying with NERC standards.		
Measure				
Requirement	R3. For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:	R3. For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:		
Measure				
Requirement	R3.1. A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.	R3.1. A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions		

**ARC Operations Work Group Assessment and Conversion of NERC PER-002-0 to Alberta Standard PER-002-AB-0
Operating Personnel Training**

Section	NERC PER-002-0	Alberta PER-002-AB-0	Reason for Difference	Comments ⁵⁵
		for the Transmission Operator and Balancing Authority operating positions.		
Measure				
Requirement	R3.2. The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.	R3.2. The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.		
Measure				
Requirement	R3.3. The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.	R3.3. The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.		
Measure				
Requirement	R3.4. Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.	R3.4. Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.		
Measure				
Requirement	R4. For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at	R4. For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority		

**ARC Operations Work Group Assessment and Conversion of NERC PER-002-0 to Alberta Standard PER-002-AB-0
Operating Personnel Training**

Section	NERC PER-002-0	Alberta PER-002-AB-0	Reason for Difference	Comments ⁵⁵
	least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.		
Measure	M1. The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.	M1. The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.		
Requirement				
Measure				
Procedures				
Compliance	<p>1. Compliance Monitoring Process Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.</p> <p>1.1. Compliance Monitoring Responsibility Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.</p> <p>1.2. Compliance Monitoring Period and Reset</p>		<p>There is no compliance section currently proposed in the Alberta Reliability Standards.</p> <p>A compliance program will be developed at a later date for Alberta Reliability Standards that recognizes the compliance monitoring and enforcement structure in Alberta.</p>	

**ARC Operations Work Group Assessment and Conversion of NERC PER-002-0 to Alberta Standard PER-002-AB-0
Operating Personnel Training**

Section	NERC PER-002-0	Alberta PER-002-AB-0	Reason for Difference	Comments ⁵⁵
	<p>Timeframe One calendar year.</p> <p>1.3. Data Retention Three years.</p> <p>1.4. Additional Compliance Information Not specified.</p> <p>2. Levels of Non-Compliance</p> <p>2.1. Level 1: N/A.</p> <p>2.2. Level 2: The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.</p> <p>2.3. Level 3: The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.</p> <p>2.4. Level 4: A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.</p>		<p>This approach is deemed consistent with the existing ISO Rules.</p>	
Regional Differences	None identified.	None identified.	Not applicable in Alberta	

Standard Owner:

Doug Hincks, Director – Operations Support

AESO Requirement Owner(s):



AESO Subject Matter Expert(s):

Bruce Fauvelle, System Control Trainer

Work Group Comments:

None

Work Group Recommendation:

The Operations Work Group recommends the AESO Reliability Committee to consider this NERC reliability standard as not applicable in Alberta.

Developed by:

Name	Organization	Role
Doug Hincks	AESO	OWG – Chair
Jerry Mossing	AESO	OWG – Previous Chair
Ken Gardner	AESO	Reliability Standards Technical Specialist
Bruce Fauvelle	AESO	Subject Matter Expert
Dwayne Aasberg	Dow Chemical	OWG – Team member
Anirban Bosu	TransAlta	OWG – Team member
Dan Bamber	TransAlta	OWG – Team member
Blaine Beisiegel	ATCO Electric	OWG – Team member
Rick Spyker	AltaLink	OWG – Team member
Michael Taylor	Capital Power	OWG – Team member
Neil Curtis	AESO	OWG – Alternate Chair



Name	Organization	Role
Stew Purkis	City of Lethbridge	OWG – Team member
Chris Best	TransCanada	OWG – Team member
Gerry Young	Suncor	OWG – Team member
Roy Hanson	ENMAX CEC	OWG – Team member
Cal Lenz	ATCO Power	OWG – Team member
Subrota Bairgi	Suncor	OWG – Team member
Amber Kirby	Capital Power	OWG – Team member
Blaise Smith	TransAlta	OWG – Team member
Penny Haldane	ENMAX	OWG – Team member