



AESO Reliability Committee (ARC)

June 28, 2010

Alberta Electric System Operator

Conference Call:

Dial-in # 1-866-835-7781 Conf Code: 5384715796

9:00 am – 12:00 noon

Agenda

1. Action items from last meeting

Jerry Mossing

- AESO to discuss effective date with ATCO Electric and AltaLink Management based on the requirements and the 4 DME stations
- AESO requested to review, with the ARC Technical Work Group, the RAS database for correct allocations and the Classification of Remedial Action Schemes and Applicability to Reliability Standards document – specifically around processes and classification criteria.
- PRC-005-AB-1 - ARC Technical WG members are requested to identify specific reasons if 180 days is unreasonable.
- AESO to review request for default effective dates and respond.

2. Standards recommendations from workgroups

Jerry Mossing/
Neil Curtis

- [BAL-005-AB-0.1b](#)
- [FAC-010-AB-2](#)
- [FAC-014-AB-2](#)
- [MOD-024-AB-1](#)
- [MOD-025-AB-1](#)
- [MOD-029-AB-1](#)

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

Jerry Mossing

- [FAC-011](#)

4. Status update on PRC-005-AB-1.

Jerry Mossing

5. Discussion, future meeting dates

Jerry Mossing

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference ¹	Comments ²
Purpose	This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.	The purpose of this reliability standard is to establish requirements for ISO automatic generation control that is necessary to calculate the area control error and to routinely deploy the regulating reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a balancing area so that balancing of resources and demand can be achieved.		Related OPPs are OPP 401 & 405
Applicability	4.1. Balancing Authorities 4.2. Generator Operators 4.3. Transmission Operators 4.4. Load Serving Entities	This reliability standard applies to: <ul style="list-style-type: none"> • ISO • TFOs 		
Effective Date		Ninety calendar days after the date of approval by the Commission.		
Requirement	R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.		Alberta Variance³: NERC requirement R1 in BAL-005-0.1b effectively applies to GFOs, TFOs and	

¹ 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”.

² Including the identification of issues, compliance ideas and identification of exempt entities.

³ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference¹	Comments²
			demand customers and all generation units, transmission and load connected to the AIES are subject to the ISO Tariff and are required to be within the metered boundaries of the Alberta balancing area. Consequently, it is not necessary to include NERC requirement R1 and its subsections in the Alberta reliability standard.	
Measure				
Requirement	R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.			
Measure				
Requirement	R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.			
Measure				
Requirement	R1.3. Each Load-Serving Entity with			

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference¹	Comments²
	load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.			
Measure				
Requirement	R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.	R1 The ISO must maintain regulating reserve that can be controlled by automatic generation control to meet the control performance standard.		RO – Real Time Operations Manager
Measure		MR1 Evidence exists and shows that the ISO has maintained regulating reserve as specified in requirement R1.		
Requirement	R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.	R2 The ISO, when providing regulation service, must ensure that adequate metering, communications, and control equipment are employed to prevent such service from having an adverse impact on the reliable operation of the Interconnection or other balancing authority areas.		RO – John Kehler
Measure		MR2 Evidence of adequate metering, communications and control equipment exists as specified in requirement R2.		
Requirement	R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide	R3 The ISO must, as soon as it is unable to provide regulation service, notify the balancing authority for whom it is providing regulation		RO – Real Time Operations Manager

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference ¹	Comments ²
	the service, as well as any Intermediate Balancing Authorities.	service, as well as any intermediate balancing authorities.		
Measure		MR3 Evidence exists and shows that the notification occurred as specified in requirement R3.		
Requirement	R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.	R4 When the ISO is receiving regulation service it must ensure that backup plans are in place to provide replacement regulation service should the supplying balancing authority no longer be able to provide this service.		RO – John Kehler
Measure		MR4 Where the ISO has received regulation service, backup plans exist as specified in requirement R4.		
Requirement	R6. The Balancing Authority’s AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority’s ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.	<p>R5 The ISO’s automatic generation control must compare total net actual interchange to total net scheduled interchange plus frequency bias obligation to determine its area control error.</p> <p>R6 When the ISO is operating asynchronously, it may employ alternative area control error calculations which include, but are not limited to, frequency control.</p> <p>R7 If the ISO is unable to calculate the area control error for more than 30 minutes, it must notify the WECC Reliability Coordinator.</p>		<p>RO for R5 – EMS Operations Manager</p> <p>RO for R6 – Real Time Operations Manager</p> <p>RO for R7 – Real Time Operations Manager</p>

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference ¹	Comments ²
Measure		<p>MR5 Evidence exists and shows that the ISO conducted the comparison to determine its area control error.</p> <p>MR6 Where the AIES was operating asynchronously, evidence exists and shows that alternative area control error calculations occurred.</p> <p>MR7 Where the area control error was unable to be calculated for more than 30 minutes, evidence exists and shows that the ISO notified the WECC Reliability Coordinator.</p>		
Requirement	<p>R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.</p>	<p>R8 Subject to requirement R9, the ISO must operate automatic generation control continuously unless such operation adversely impacts the reliability of the Interconnection.</p> <p>R9 The ISO must, If automatic generation control has become inoperative, use manual controls to adjust generation to maintain the net scheduled interchange.</p>		<p>RO for R8 – Real Time Operations Manager</p> <p>RO for R9 – Real Time Operations Manager</p>

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference ¹	Comments ²
Measure		<p>MR8 Where the automatic generation control was not continuously operated, evidence exists such as shift logs to confirm the operation would have adversely impacted the reliability of the Interconnection.</p> <p>MR9 Where the automatic generation control was inoperative, evidence exists such shift logs, voice recordings, dispatch logs and emails to confirm the manual control occurred as specified in requirement R9.</p>		
Requirement	R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.	R10 The ISO must ensure that data acquisition for, and calculation of, the area control error occurs at least every six seconds.		RO for R10 – EMS Operations Manager
Measure		MR10 Evidence exists and shows that the data acquisition for and calculation of area control error has occurred as specified in requirement R10.		
Requirement	R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.	<p>R10.1 The ISO must provide or ensure redundant and independent frequency metering equipment that automatically activates upon detection of failure of the primary source.</p> <p>R10.2 The equipment specified in requirement R10.1 must have a</p>		RO for R10.1 and 10.2 – EMS Operations Manager

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference¹	Comments²
		minimum availability of 99.95%.		
Measure		<p>MR10.1 Evidence of redundant and independent frequency metering equipment exists and operates as specified in requirement R10.1.</p> <p>MR10.2 Evidence exists and shows that the minimum availability was met as specified in requirement R10.2.</p>		
Requirement	R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.	R11 Subject to requirement 11.1, the ISO must include all interchange schedules with adjacent balancing authorities in the calculation of net scheduled interchange for the area control error equation.		RO for R11 – EMS Operations Manager
Measure		MR11 Evidence exists and shows that the ISO included interchange schedules as specified in requirement R11.		
Requirement	R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.	R11.1 The ISO may omit the interchange schedule for a high voltage direct current link to another balancing authority from the area control error equation if it is modeled as internal generation or load.		RO – EMS Operations Manager

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference¹	Comments²
Measure		MR11.1 Evidence exists and shows that the ISO accounted for a high voltage direct current link as specified in requirement R11.1.		
Requirement	R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	R12 The ISO must include all dynamic schedules in the calculation of net scheduled interchange for the area control error equation.		RO – EMS Operations Manager
Measure		MR12 Evidence exists and shows that dynamic schedules have been included in the calculation as specified in requirement R12.		
Requirement	R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.	R13 The ISO must include the effect of ramp rates, which must be identical and agreed to between affected balancing authorities, in the scheduled interchange values to calculate the area control error.		RO – EMS Operations Manager
Measure		MR13 Evidence exists and shows the effect of ramp rates have been included in the calculation of the area control error as specified in requirement R13.		
Requirement	R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.	R14 The ISO must include all synchronous interconnection real power flows in the area control error calculation.		RO – EMS Operations Manager

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference¹	Comments²
Measure		MR14 Evidence exists and shows all synchronous interconnection real power flows have been included in the calculation as specified in requirement R14.		
Requirement	R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.	R14.1 The ISO and balancing authorities that share a synchronous interconnection must ensure that tie line MW metering is telemetered to both control centers, and emanates from a common source using common primary metering equipment. R14.2 The ISO and balancing authorities that share a synchronous interconnection must ensure that MWh data is telemetered or reported to both control centers at the end of each hour.		RO for R14.1 - Dan Shield RO for R14.2 - Dan Shield for the physical connections and the EMS Operations Manager for hourly data.
Measure		MR14.1 Evidence exists and shows that data emanates from a common source and is shared with both control centers using the equipment specified in requirement R14.1. MR14.2 Evidence exists and shows that data is shared with both control centers within the time frame specified in requirement R14.2.		
Requirement	R12.2. Balancing Authorities shall ensure the power flow and ACE	R14.3 The ISO must ensure that unfiltered tie line MW and area		RO for 14.3 and 14.4 – EMS

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference ¹	Comments ²
	signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.	control error signals are used for calculating performance except for the anti-aliasing filters of tie lines. R14.4 The ISO must ensure tie line MW and area control error signals that are transmitted for regulation service are not filtered prior to transmission, except for the anti-aliasing filters of tie lines.		Operations Manager
Measure		MR14.3 Evidence exists and shows the signals are used for calculating performance as specified in requirement R14.3. MR14.4 Evidence exists and shows the tie line MW and area control error signals for regulation service have been transmitted as specified in requirement R14.4.		
Requirement	R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.	R14.5 The ISO and balancing authorities must ensure common metering equipment has been installed where dynamic schedules or pseudo-ties are implemented between the ISO and one or more balancing authorities to deliver the output of jointly owned units or to serve remote load.		RO for 14.5 – EMS Operations Manager

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference ¹	Comments ²
Measure		MR14.5 Where dynamic schedules or pseudo-ties have been implemented, evidence exists and shows that metering equipment has been installed as specified in requirement R14.5.		
Requirement	R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.	R15. The ISO must perform hourly error checks using tie line MWh meters with common time synchronization to determine the accuracy of its control equipment. The ISO must adjust the component of the area control error that is in error, if known, or use the interchange meter error term of the area control error equation, to compensate for any equipment error until repairs can be made.		RO – Real Time Operations Manager
Measure		MR15 Evidence exists and shows that the ISO performed hourly error checks and adjusted the component of the area control error, as necessary, as specified in requirement R15.		
Requirement	R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel	R16. The ISO must provide its operating personnel with real-time values for the area control error, Interconnection frequency and net actual interchange with each adjacent balancing authority area. R17 The ISO must provide its operating personnel with sufficient		RO for R16 – EMS Operations Manager Instrumentation is the frequency transducer in the control centre.

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference¹	Comments²
	with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.	instrumentation, data and recording equipment to facilitate the monitoring of control performance, generation response, and after-the-fact analysis of area performance.		RO for R17 – EMS Operations Manager
Measure		<p>MR16 Evidence exists and shows that the ISO provided real-time values to its operating personnel as specified in requirement R16.</p> <p>MR17 Evidence exists and shows that the ISO provided its operating personnel with the instrumentation and information as specified in requirement R17.</p>		
Requirement	R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority’s control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.	R18 The ISO must provide adequate and reliable backup power supplies and must periodically test these supplies at the ISO’s control center and other critical locations to ensure continuous operation of the automatic generation control and vital data recording equipment during loss of the normal power supply.		RO – SCC Facilities Manager
Measure		MR18 Evidence exists and shows that the ISO has provided adequate and reliable backup power supplies, and has periodically tested the equipment as specified in requirement R18.		
Requirement	R16. The Balancing Authority shall	R19 The ISO must sample area		RO – EMS

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control												
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference ¹	Comments ²								
	sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.	control error related data, at minimum, with the same frequency in which the area control error is calculated. The ISO must flag missing or bad area control error related data for operator display and archival purposes. The ISO must collect coincident area control error related data to the greatest extent practical.		Operations Manager								
Measure		MR19 Evidence exists and shows that the ISO has sampled area control error related data, has flagged bad or missing data for operator display, and has collected coincident data as specified in requirement R19.										
Requirement	<p>R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:</p> <table border="0"> <tr> <td>Device</td> <td style="text-align: right;">Accuracy</td> </tr> <tr> <td>Digital frequency transducer</td> <td style="text-align: right;">≤ 0.001 Hz</td> </tr> <tr> <td>MW, MVAR, and voltage transducer</td> <td style="text-align: right;">≤ 0.25 % of full scale</td> </tr> <tr> <td>Remote terminal unit</td> <td style="text-align: right;">≤ 0.25 % of full scale</td> </tr> </table>	Device	Accuracy	Digital frequency transducer	≤ 0.001 Hz	MW, MVAR, and voltage transducer	≤ 0.25 % of full scale	Remote terminal unit	≤ 0.25 % of full scale	<p>R20 The ISO and each TFO must, subject to requirement R21, at minimum, conduct an annual check and calibration of its time error and frequency devices, used for AGC, against a common reference.</p> <p>R21 The ISO and each TFO are not required to check and calibrate devices where the manufacturer's specification of such devices does not require calibration.</p> <p>R22 If the ISO has measuring devices used for automatic</p>		<p>RO for R20 – EMS Operations Manager</p> <p>RO for R21 – EMS Operations Manager</p> <p>RO for R22 – EMS Operations Manager</p>
Device	Accuracy											
Digital frequency transducer	≤ 0.001 Hz											
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale											
Remote terminal unit	≤ 0.25 % of full scale											

Assessment and Conversion of NERC BAL-005-0.1b to Alberta BAL-005-AB-0.1b Automatic Generation Control				
Section	NERC BAL-005-0.1b	Alberta BAL-005-AB-0.1b	Reason for Difference ¹	Comments ²
Measure		<p>MR20 Evidence exists and shows that an annual check and calibration has occurred as specified in requirement R20.</p> <p>MR21 Evidence exists that the device(s) do not require calibration as specified in requirement R21.</p> <p>MR22 Evidence exists and shows that the measuring devices used by the ISO meet the minimum values as specified in requirement R21.</p> <p>MR23 Evidence exists and shows that the measuring devices used for automatic generation control data meet the minimum values as specified in requirement R21.</p>		
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/BAL-005-0_1b.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	None identified.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary:

“anti-aliasing filter” means an analog filter installed at a metering point to remove the high frequency components of the signal over the *automatic generation control* sample period.

“regulation service” means the process whereby one *balancing authority* contracts to provide corrective response to all or a portion of the *area control error* of another *balancing authority*.

Existing Defined Terms Used in this Standard:

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

- adjacent balancing authority
- automatic generation control
- area control error
- balancing authority
- balancing authority area
- Commission
- days
- demand
- facilities
- frequency bias
- generation facility owner (GFO)
- Interconnection
- ISO
- load
- MW
- net actual interchange
- net schedule interchange
- regulating reserve
- reliability standard
- transmission facility owner (TFO)
- WECC

Standard Owner:

Neil Curtis, Director, Grid and Market Operations

AESO Requirement Owner(s):

The Real Time Operations Manager is the requirement owner for requirements R1, R3, R6, R7, R8, R9 and R15.

AESO Reliability Committee (ARC) Agenda - Continued

John Kehler, Technical Lead – System Performance is the requirement owner for requirements R2 and R4.

The EMS Operations Manager is the requirement owner for requirements R5, R10, R10.1, R10.2, R11, R11.1, R12, R13, R14, R14.2 (for hourly data), R14.3, R14.4, R14.5, R16, R17, R19, R20 and R21.

Dan Shield, Technical Specialist – Engineering is the requirement owner for requirements R14.1, R14.2 (for the physical connections), SCC Facilities Manager is the requirement owner for requirement R18

AESO Subject Matter Expert(s):

John Kehler, Technical Lead – System Performance

Kevin Wiens, Analyst – System Performance

Dan Shield, Technical Specialist – Engineering

Work Group Comments:

No outstanding comments or concerns.

Work Group Response:

Not required.

Work Group Recommendation:

The OWG members support the recommendation to submit this reliability standard to the ARC.

Developed by:

Name	Organization	Role
John Kehler	AESO	Senior Technical Specialist, Operations Planning
Kevin Wiens	AESO	Senior Technical Specialist, Operations Planning
Mark Thompson	AESO	OWG member
Neil Curtis	AESO	Standard Owner
Ken Gardner	AESO	Reliability Standards Specialist
Anirban Bosu	TransAlta	OWG member
Ron Smith	AESO	OWG member
Mark Thompson	AESO	OWG member
Peter Tam	AESO	OWG member

AESO Reliability Committee (ARC) Agenda - Continued

Name	Organization	Role
Dan Shield	AESO	Subject Matter Expert
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
Elizabeth Olivier	Consultant	Technical writer review
Larry Kram	AESO	Legal review
Amber Kirby	Capital Power	OWG member
Blaise Smith	TransAlta	OWG member
Stew Purkis	City of Lethbridge	OWG member
Travis Robinson	EPCOR	OWG member
Peter Bartsch	AltaLink	OWG member
Roy Hanson	ENMAX Generation	OWG member
Subrota Bairagi	Suncor	OWG member

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference⁴	Comments⁵
Purpose	To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	The purpose of this reliability standard is to ensure that system operating limits used in the reliable planning of the bulk electric system are determined based on an established methodology or methodologies.		
Applicability	4.1. Planning Authority	This reliability standard applies to: <ul style="list-style-type: none"> • ISO 		
Effective Date	4.1. Planning Authority	Ninety calendar days after the date of approval by the Commission.		
Requirement	R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	R1 The ISO must have an established and documented system operating limit methodology for use in developing system operating limits within its planning authority area. This system operating limit methodology must, without limitation, do the following:		Requirement Owner – Jeff Billinton for all requirements
Measure		MR1 Evidence of a documented system operating limit methodology exists and includes the components as specified in requirement R1 through requirement R1.3.		
Requirement	R1.1. Be applicable for developing SOLs used in the planning	R1.1. Be applicable for developing system operating limits used in the ISO's		

⁴ 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.

⁵ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
	horizon.	planning horizon.		
Measure				
Requirement	R1.2. State that SOLs shall not exceed associated Facility Ratings.	R1.2. State that system operating limits must not exceed associated facility ratings.		
Measure				
Requirement	R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.	R1.3. Include a description of how to identify the subset of system operating limits that qualify as interconnected reliability operating limits.		
Measure				
Requirement	R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	R2 The methodology established in requirement R 1 must provide for bulk electric system performance consistent with the following:		
Measure		MR2 Evidence exists to confirm the system operating limits methodology addresses the items as specified in requirement R2.1 through requirement R2.10.		
Requirement	R2.1. In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such	R2.1. In the pre-contingency state and with all facilities in service, <ul style="list-style-type: none"> • transient, dynamic and voltage stability; • all facilities must be within their facility ratings and stability limits; and • reflection of expected system conditions and changes to system topology. 	Facility ratings include thermal and voltage limits. Alberta Variance: In the planning time horizon facility outages are generally not analyzed. These will be addressed in the operational system operating limits.	

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
	as Facility outages.			
Measure				
Requirement	<p>R2.2. Following the single Contingencies¹ identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.</p> <p>¹ The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.</p>	<p>R2.2 Following any single contingency as specified in requirements R 2.2.1 through to R2.2.3, inclusive, the system must demonstrate:</p> <ul style="list-style-type: none"> • transient, dynamic and voltage stability; • all facilities operating within their facility ratings, stability limits; and • no cascading or uncontrolled separation. 	<p>Alberta Variance⁶: The following footnote in the NERC standard is not a specific requirement and was deleted from the Alberta reliability standard: “The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.”</p>	
Measure				
Requirement	<p>R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.</p>	<p>R2.2.1. Single line to ground fault or three-phase fault, whichever is most severe, with normal clearing, on any faulted generator, line, transformer, or shunt device.</p>		
Measure				
Requirement	<p>R2.2.2. Loss of any generator, line, transformer, or shunt device</p>	<p>R2.2.2. Loss of any generating unit, line, transformer, or shunt device without a</p>		

⁶ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
	without a Fault.	fault.		
Measure				
Requirement	R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	R2.2.3. Single pole block, with normal clearing, in a monopolar or bipolar high voltage direct current system.		
Measure				
Requirement	R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	R2.3. With all facilities in service, the system's response to a single contingency, may include without limitation, any of the following:		
Measure				
Requirement	R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the faulted facility or by the affected area.		
Measure				
Requirement	R2.3.2. System reconfiguration through manual or automatic control or protection actions.	R2.3.2. System reconfiguration through manual or automatic control or protection actions.		
Measure				
Requirement	R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	R2.4. To prepare for the next contingency, system adjustments may be made, including without limitation, changes to generation, uses of the transmission system, and the transmission system topology.		
Measure				
Requirement	R2.5. Starting with all Facilities in service and following any of the	R2.5. With all facilities in service and following any of the multiple		

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
	multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	contingencies identified in Alberta reliability standard TPL-003-AB the system must demonstrate: <ul style="list-style-type: none"> transient, dynamic and voltage stability; all facilities operating within their facility ratings and stability limits; and no cascading or uncontrolled separation. 		
Measure				
Requirement	R2.6. In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	R2.6. In determining the system's response to any of the multiple contingencies, identified in Alberta reliability standard TPL-003-AB, in addition to the responses and actions identified in requirements R2.3.1 and R2.3.2, the following are acceptable:		
Measure				
Requirement	R2.6.1. Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	R2.6.1. Planned or controlled interruption of demand to demand customers, the planned removal of generating units, or the curtailment of firm (non-recallable) power transfers.		
	E1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:		Requirements in the NERC Reliability Standard FAC-010 within section E relate to WECC Interconnection-wide	

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
			Regional Differences. These requirements have been brought into the applicable section of the Alberta Standard.	
Requirement	E1.1. As governed by the requirements of R2.4 and R2.5, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:	R2.7 When the ISO is establishing system operating limits on interconnections to other WECC jurisdictions, in addition to requirements R2.4 and R2.5, with all facilities in service, must evaluate of the following multiple facility contingencies	Alberta Variance⁷: This is consistent with the intent of WRS1 of the WECC regional criteria TPL – (001 thru 004) – WECC – 1 – CR – System Performance Criteria.	
Measure				
Requirement	E1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.	R2.7.1 Simultaneous permanent phase to ground faults of each of two adjacent transmission circuits on a multiple circuit tower, with normal clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, this condition is an acceptable risk and therefore can be excluded.	Alberta Variance⁸: WECC has identified this in a SAR to make this change.	

⁷ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

⁸ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
Measure				
Requirement	E1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7	R2.7.2 A permanent phase to ground fault on any generator, transmission circuit, transformer, or bus section with delayed fault clearing except for bus sectionalizing breakers or bus tie breakers as specified addressed in requirement R.2.7.7		
Measure				
Requirement	E1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.	R2.7.3 Simultaneous permanent loss of both poles of a direct current bipolar facility without an alternating current fault.		
Measure				
Requirement	E1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.	R2.7.4 The failure of a circuit breaker associated with a remedial action scheme to operate when required following: the loss of any element without a fault; or a permanent phase to ground fault, with normal clearing, on any transmission circuit, transformer or bus section.		
Measure				
Requirement	E1.1.5 A non-three phase Fault with Normal Clearing on common	R2.7.5 A single-line-to-ground fault with normal clearing on common mode	Alberta Variance⁹: WECC has identified	

⁹ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference⁴	Comments⁵
	mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.	contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in 30 years.	this in a SAR to make this change.	
Measure				
Requirement	E1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.	R2.7.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010-AB.		
Measure				
Requirement	E1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.	R2.7.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent phase to ground fault.		
Measure				
Requirement	E1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:	R2.8. System operating limits must be established such that for multiple facility contingencies as specified in requirement R2.7.1 through requirement R2.7.5, operation within the system operating limit must provide system performance consistent with the following on interconnections to other WECC jurisdictions:		
Measure				
Requirement	E1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.	R2.8.1 All facilities are operating within their applicable post-contingency thermal, frequency and voltage limits.		
Measure				

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference⁴	Comments⁵
Requirement	E1.2.2 Cascading Outages do not occur.	R2.8.2 Cascading outages do not occur.		
Measure				
Requirement	E1.2.3 Uncontrolled separation of the system does not occur.	R2.8.3 Uncontrolled separation of the system does not occur.		
Measure				
Requirement	E1.2.4 The system demonstrates transient, dynamic and voltage stability.	R2.8.4 The system demonstrates transient, dynamic and voltage stability.		
Measure				
Requirement	E1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.	R2.8.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generating units , and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.		
Measure				
Requirement	E1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.	R2.8.6 Interruption of firm transfer, load or system reconfiguration is permitted through manual or automatic control or protection actions.		
Measure				
Requirement	E1.2.7 To prepare for the next	R2.8.7 To prepare for the next		

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
	Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.	contingency, system adjustments are permitted, including changes to generation, load and the transmission system topology when determining limits.		
Measure				
Requirement	E1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:	R2.9. System operating limits must be established such that for multiple facility contingencies as specified in requirement R2.7.6 and requirement R2.7.7 operation within the system operating limit must provide system performance such that cascading outages do not occur on interconnections to other WECC jurisdictions.	Clarified that other systems refers to interconnections to other WECC jurisdictions. Combined sub-requirement R2.9.1 into requirement R2.9.	
Measure				
Requirement	E1.3.1 Cascading Outages do not occur.		Combined sub-requirement R2.9.1 into requirement R2.9.	
Measure				
Requirement	E1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.	R2.10. For the ISO to make changes (performance category adjustments) to the contingencies required to be studied and/or the required responses to contingencies for specific facilities on interconnections to other WECC jurisdictions, the ISO must do so in accordance with the applicable WECC process.		
Measure				
Requirement	R3. The Planning Authority's	R3. The ISO's methodology for		

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference⁴	Comments⁵
	methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	determining system operating limits, must include, without limitation, a description of the following, along with any reliability margins applied for each:		
Measure	M1. The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.	MR3 Evidence exists to confirm the system operating limits methodology addresses the items as specified in requirement R3.1 through requirement R3.6.		
Requirement	R3.1. Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	R3.1. Study model must include at least the entire planning authority area as well as the critical modeling details from other planning authority areas that would impact the facility or facilities under study.		
Measure				
Requirement	R3.2. Selection of applicable Contingencies.	R3.2. Selection of applicable contingencies.		
Measure				
Requirement	R3.3. Level of detail of system models used to determine SOLs.	R3.3. Level of detail of system models used to determine system operating limits		
Measure				
Requirement	R3.4. Allowed uses of Special Protection Systems or Remedial Action Plans.	R3.4. Allowed uses of remedial action schemes or remedial action plans.		
Measure				
Requirement	R3.5. Anticipated transmission system configuration, generation dispatch and Load level.	R3.5. Anticipated transmission system configuration, generation dispatch and load level.		

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
Measure				
Requirement	R3.6. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tv.	R3.6. Criteria for determining when violating a system operating limit qualifies as an interconnection reliability operating limit and criteria for developing any associated interconnection reliability operating limit Tv.		
Measure				
Requirement	R4. The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:	R4. The ISO must issue its system operating limit methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		
Measure	M2. The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.	MR4. Evidence exists that the ISO issued its system operating limit methodology as specified in requirement R4 through requirement R4.2.		
Requirement	R4.1. Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	R4.1. Each adjacent planning authority and each planning authority that indicated it has a reliability-related need for the methodology.		
Measure				
Requirement	R4.2. Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	R4.2. The WECC Reliability Coordinator.	The ISO has this responsibility.	
Measure				
Requirement	R4.3. Each Transmission Planner that works in the Planning		The ISO has this responsibility.	

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
	Authority's Planning Authority Area.			
Measure				
Requirement	R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.	R5 If a recipient of the system operating limit methodology as specified in requirement R4, provides documented technical comments on the methodology, the ISO must provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response must indicate whether a change will be made to the system operating limit methodology and, if no change will be made to that system operating limit methodology, the reason why.		
Measure	M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5.	MR5. Where documented technical comments were received by the ISO from a recipient of the system operating methodology, evidence exists the ISO provided a response as specified in requirement R5.		
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/FAC-010_2.pdf		There is no compliance section currently proposed in the Alberta Reliability Standards.	

ARC Transmission Planning Work Group Assessment and Conversion of NERC FAC-010-2 to Alberta FAC-010-AB-2 System Operating Limits Methodology for the Planning Horizon				
Section	NERC FAC-010-2	Alberta FAC-010-AB-2	Reason for Difference ⁴	Comments ⁵
			<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>	

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)

- bulk electric system
- cascading
- contingencies
- dispatch
- element
- facilities
- facility rating
- firm
- interconnection
- interconnection reliability operating limits (IROL)
- ISO
- load
- normal clearing

- outage
- reliability
- reliability standard
- remedial action scheme (RAS)
- stability
- stability limits
- system
- system operating limits
- WECC

Standard Owner:

Jerry Mossing, Director - Transmission Support

AESO Requirement Owner(s):

Jeff Billinton, Technical Specialist, Long Term Planning is the requirement owner for all requirements in this standard.

AESO Subject Matter Expert(s):

Steve Heidt, Manager - Technical Resource

Work Group Comments:

No outstanding comments or concerns.

Work Group Response:

Not required.

AESO Comments:

Please note that this reliability standard is currently being reviewed by AESO legal counsel.

Work Group Recommendation:

The OWG members support the recommendation to submit this reliability standard to the ARC.

Developed by:

AESO Reliability Committee (ARC) Agenda - Continued

Name	Organization	Role
Jerry Mossing	AESO	OWG Chair
Ken Gardner	AESO	Reliability Standards Specialist
Jeff Billinton	AESO	TPWG Chair
Steve Heidt	AESO	Subject Matter Expert
Nancy Cameron	AESO	Measures Development
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
Blaise Smith	TransAlta	OWG member
Stew Purkis	City of Lethbridge	OWG member
Travis Robinson	EPCOR	OWG member

Name	Organization	Role
Peter Bartsch	AltaLink	OWG member

ARC Operation Work Group Assessment and Conversion of NERC FAC-011-2 to Alberta FAC-011-AB-2 System Operating Limits Methodology for the Operations Horizon				
Section	NERC FAC-011-2	Alberta FAC-011-AB-2	Reason for Difference¹⁰	Comments¹¹
Purpose	To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.		This standard is recommended to be not applicable in Alberta as all requirements apply to the Reliability Coordinator. – Refer to the AESO Comments section below.	
Applicability	4.1. Reliability Coordinator			
Effective Date	October 1, 2008			
Requirement	R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:			
Measure				
Requirement	R1.1. Be applicable for developing SOLs used in the operations horizon.			
Measure				
Requirement	R1.2. State that SOLs shall not exceed associated Facility Ratings.			

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 Operation Work Group Assessment and Conversion of NERC FAC-011-2 to Alberta FAC-011-AB-2 System Operating Limits Methodology for the Operations Horizon				
Section	NERC FAC-011-2	Alberta FAC-011-AB-2	Reason for Difference¹⁰	Comments¹¹
Measure				
Requirement	R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.			
Measure				
Requirement	R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:			
Measure				
Requirement	R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.			
Measure				
Requirement	R2.2. Following the single Contingencies ¹ identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.			
Measure				
Requirement	R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.			

ARC Operation Work Group Assessment and Conversion of NERC FAC-011-2 to Alberta FAC-011-AB-2 System Operating Limits Methodology for the Operations Horizon				
Section	NERC FAC-011-2	Alberta FAC-011-AB-2	Reason for Difference¹⁰	Comments¹¹
Measure				
Requirement	R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.			
Measure				
Requirement	R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.			
Measure				
Requirement	R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:			
Measure				
Requirement	R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.			
Measure				
Requirement	R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies			
Measure				
Requirement	R2.3.3. System reconfiguration through manual or automatic control or protection actions.			
Measure				
Requirement	R2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission			

ARC Operation Work Group Assessment and Conversion of NERC FAC-011-2 to Alberta FAC-011-AB-2 System Operating Limits Methodology for the Operations Horizon				
Section	NERC FAC-011-2	Alberta FAC-011-AB-2	Reason for Difference¹⁰	Comments¹¹
	system topology.			
Measure				
Requirement	R3. The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:			
Measure				
Requirement	R3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)			
Measure				
Requirement	R3.2. Selection of applicable Contingencies			
Measure				
Requirement	R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.			
Measure				
Requirement	R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.			
Measure				
Requirement	R3.4. Level of detail of system models used to determine SOLs.			
Measure				
Requirement	R3.5. Allowed uses of Special Protection			

ARC Operation Work Group Assessment and Conversion of NERC FAC-011-2 to Alberta FAC-011-AB-2 System Operating Limits Methodology for the Operations Horizon				
Section	NERC FAC-011-2	Alberta FAC-011-AB-2	Reason for Difference¹⁰	Comments¹¹
	Systems or Remedial Action Plans.			
Measure				
Requirement	R3.6. Anticipated transmission system configuration, generation dispatch and Load level.			
Measure				
Requirement	R3.7. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tv.			
Measure	M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.			
Requirement	R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:			
Measure				
Requirement	R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.			
Measure				
Requirement	R4.2. Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.			
Measure				
Requirement	R4.3. Each Transmission Operator that operates in the Reliability Coordinator Area.			

ARC Operation Work Group Assessment and Conversion of NERC FAC-011-2 to Alberta FAC-011-AB-2 System Operating Limits Methodology for the Operations Horizon				
Section	NERC FAC-011-2	Alberta FAC-011-AB-2	Reason for Difference¹⁰	Comments¹¹
Measure	M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.			
Requirement	R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.			
Measure	M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5			
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/FAC-011_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 FAC-011-2 to Alberta FAC-011-AB-2 System Operating Limits Methodology for the Operations Horizon				
Section	NERC FAC-011-2	Alberta FAC-011-AB-2	Reason for Difference¹⁰	Comments¹¹
			and enforcement structure in Alberta. This approach is deemed consistent with the existing ISO Rules.	
Regional Differences	To view the regional differences section E of the NERC reliability standard follow the link above in the compliance section.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary:

Not applicable

Existing Defined Terms Used in this Standard:

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

Not applicable

Standard Owner:

Jerry Mossing, Director – Transmission Support

AESO Requirement Owner(s):

Not applicable

AESO Subject Matter Expert(s):

Work Group Comments:

No outstanding comments or concerns.

Work Group Response:

Not required.

AESO Comments:

The WECC has not posted anything in its RRO document area (although this is an RC document not an RRO document). BCTC has sent AESO a copy of their SOL Methodology for both planning (FAC-010) and operations (FAC-011). Recommend that AESO reject this standard and without regard to FAC-011, develop an Operations SOL methodology in conjunction with the planning SOL methodology for application in Ablerta. This would be consistent with AESO legislated duties and could be made consistent with the FAC-011 whenever WECC RC produces an operations based SOL methodology. – Jerry

Work Group Recommendation:

The OWG members support the recommendation to submit this reliability standard to the ARC.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	ARC OWG Chair
Ken Gardner	AESO	Reliability Standards Specialist
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

AESO Reliability Committee (ARC) Agenda - Continued

Name	Organization	Role
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
Blaise Smith	TransAlta	OWG member
Stew Purkis	City of Lethbridge	OWG member
Travis Robinson	EPCOR	OWG member
Peter Bartsch	AltaLink	OWG member
Terri Haffick	ENMAX	OWG member
Michael Taylor	Capital Power Corp.	OWG member

The ARC Operations Work Group Assessment and Conversion of NERC FAC-014-2 to Alberta FAC-014-AB-2 Establish and Communicate System Operating Limits				
Section	NERC FAC-014- 2	Alberta FAC-014-AB-2	Reason for Difference¹²	Comments¹³
Purpose	To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	The purpose of this reliability standard is to establish and publish system operating limits to be used in the reliable planning and operation of the bulk electric system.		
Applicability	4.1. Reliability Coordinator 4.2. Planning Authority 4.3. Transmission Planner 4.4. Transmission Operator	This reliability standard applies to: • ISO		
Effective Date	January 1, 2009	Thirty calendar days after the date of approval by the Commission.		
Requirement	R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.		Not applicable – applies to the WECC Reliability Coordinator.	
Measure				
Requirement	R2. The Transmission Operator shall	R1 The ISO must establish	Alberta Variance ¹⁴ : Did	ROs - Steve Heidt / Ata

¹² 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.

¹³ Including the identification of issues, compliance ideas and identification of exempt entities.

¹⁴ An Alberta variance is a change from the US Reliability Standard that the AESO has determined is material.

The ARC Operations Work Group Assessment and Conversion of NERC FAC-014-2 to Alberta FAC-014-AB-2				
Establish and Communicate System Operating Limits				
Section	NERC FAC-014- 2	Alberta FAC-014-AB-2	Reason for Difference ¹²	Comments ¹³
	establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.	system operating limits in its operations horizon that are consistent with the WECC Reliability Coordinator’s system operating limits methodology.	not adopt the wording, “as directed by its Reliability Coordinator” in accordance with the WECC/AESO Operating Agreement. However the ISO will develop SOLs consistent with the WECC Reliability Coordinator’s SOL Methodology. Added clarity in requirement R1 that the establishment of system operating limits applies in the operations time horizon.	Rehman
Measure		MR1 Evidence exists which demonstrate the ISO’s operations horizon system operating limits are consistent with the WECC’s Reliability Coordinator’s system operating limits methodology.		
Requirement	R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.	R2 The ISO must establish system operating limits in its planning horizon, including interconnection reliability operating limits, that are consistent with its system operating limits methodology.	This one is providing some difficulty – we are indicating we need to be consistent with our own SOL methodology but no where does it indicate we need a methodology in the first place.	Bill Strongman - RO
Measure	M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and	MR2 Evidence exists to demonstrate that the ISO	Measures adjusted to meet Alberta reliability	

<p align="center">The ARC Operations Work Group Assessment and Conversion of NERC FAC-014-2 to Alberta FAC-014-AB-2 Establish and Communicate System Operating Limits</p>				
Section	NERC FAC-014- 2	Alberta FAC-014-AB-2	Reason for Difference ¹²	Comments ¹³
	Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.	established its system operating limits in the planning horizon as specified in requirement R2.	standard requirements.	
Requirement	R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.		The ISO is the transmission planner and the planning authority. This requirement is therefore redundant with requirement R2.	
Measure				
Requirement	R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:	R3 The ISO must provide its system operating limits and interconnection reliability operating limits to the WECC Reliability Coordinator, interconnected transmission operators, adjacent transmission planners and TFOs that have a reliability-related need for those limits. As well, the ISO must provide a written request to each of the foregoing for a schedule for delivery of those limits as agreed to by the ISO.	Requirements R5.2 to 5.4 were rolled into R5.	Planning RO – Bill Strongman Operations RO – Steve Heidt & Ata Rehman

The ARC Operations Work Group Assessment and Conversion of NERC FAC-014-2 to Alberta FAC-014-AB-2 Establish and Communicate System Operating Limits				
Section	NERC FAC-014- 2	Alberta FAC-014-AB-2	Reason for Difference ¹²	Comments ¹³
Measure	M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.	MR3 Evidence exists to confirm the ISO provided its system operating limits and interconnection reliability operating limits as specified in requirement R3.		
Requirement	R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:		Not applicable – applies to the WECC Reliability Coordinator.	
Measure				
Requirement	R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.		Not applicable – applies to the WECC Reliability Coordinator.	
Measure				
Requirement	R5.1.2. The value of the IROL and its associated Tv.		Not applicable – applies to the WECC Reliability Coordinator.	
Measure				
Requirement	R5.1.3. The associated		Not applicable – applies to	

The ARC Operations Work Group Assessment and Conversion of NERC FAC-014-2 to Alberta FAC-014-AB-2 Establish and Communicate System Operating Limits				
Section	NERC FAC-014- 2	Alberta FAC-014-AB-2	Reason for Difference ¹²	Comments ¹³
	Contingency(ies).		the WECC Reliability Coordinator.	
Measure				
Requirement	R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).		Not applicable – applies to the WECC Reliability Coordinator.	
Measure				
Requirement	R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.		The ISO performs the role of TP, PA and TO. This requirement is therefore redundant with 5.3 and 5.4 where the ISO has the responsibilities in both of these NERC requirements.	
Measure				
Requirement	R5.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.		The ISO performs the role of TP, PA and TO. This requirement is therefore redundant with 5.2 and 5.4 where the ISO has the responsibilities in both of these NERC requirements.	
Measure				
Requirement	R5.4. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and		R5.4 was rolled into R5.	

The ARC Operations Work Group Assessment and Conversion of NERC FAC-014-2 to Alberta FAC-014-AB-2 Establish and Communicate System Operating Limits				
Section	NERC FAC-014- 2	Alberta FAC-014-AB-2	Reason for Difference ¹²	Comments ¹³
	Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.			
Measure				
Requirement	R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.	R4 The ISO must identify the subset of multiple contingencies which result in stability limits as determined from reliability standard TPL-003-AB, if any, that exist in its planning horizon.		RO – Bill Strongman
Measure	M3. The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators in accordance with Requirement 6.	MR4 Evidence exists that the ISO identified the list as specified in requirement R4.		
Requirement	R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.	R4.1 The ISO must provide this list of multiple contingencies and the associated stability limits to the WECC Reliability Coordinator.		RO – Bill Strongman
Measure		MR4.1 Evidence exists that the list was provided as specified in requirement R4.1.		
Requirement	R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	R4.2 Where the ISO has not identified any stability-related multiple contingencies, the ISO must notify the WECC Reliability		RO – Bill Strongman

The ARC Operations Work Group Assessment and Conversion of NERC FAC-014-2 to Alberta FAC-014-AB-2 Establish and Communicate System Operating Limits				
Section	NERC FAC-014- 2	Alberta FAC-014-AB-2	Reason for Difference ¹²	Comments ¹³
		Coordinator.		
Measure		MR4.2 Evidence exists that notification was made as specified in requirement R4.2.		
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/FAC-014-2.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.	
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)

- bulk electric system
- Commission

- contingencies
- days
- interconnected transmission operator
- interconnection reliability operating limits
- ISO
- reliability standard
- stability limits
- system operating limits (SOL)
- transmission facility owner (TFO)
- WECC

Standard Owner:

Jerry Mossing, Director - Transmission Support

AESO Requirement Owner(s):

Steve Heidt and Ata Rehman, Technical Resource Managers for requirements R1, R3 (operations planning component).

Bill Strongman Technical Lead - Long Term Planning for requirement R2, R3 (planning component), R4, R4.1 and R4.2.

AESO Subject Matter Expert(s):

Jeff Billinton, Technical Specialist - Long Term Planning

Work Group Comments:

No outstanding comments or concerns.

Work Group Response:

Not required.

AESO Comments:

Please note that this reliability standard is currently being reviewed by AESO legal counsel.

Work Group Recommendation:

The OWG members support the recommendation to submit this reliability standard to the ARC.

AESO Reliability Committee (ARC) Agenda - Continued

Developed by:

Name	Organization	Role
Jeff Billinton	AESO	Subject Matter Expert
Ken Gardner	AESO	Technical Specialist, Reliability Standards
Steve Heidt	AESO	Subject Matter Expert
Jerry Mossing	AESO	OWG Chair
Nancy Cameron	AESO	Measures Development
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
Blaise Smith	TransAlta	OWG member
Stew Purkis	City of Lethbridge	OWG member

Name	Organization	Role
Travis Robinson	EPCOR	OWG member
Peter Bartsch	AltaLink	OWG member

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference¹⁵	Comments¹⁶
Purpose	To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	The purpose of this reliability standard is to ensure that calculations are performed by the ISO to maintain awareness of available transmission system capability and future flows on the AIES as well as those of their neighbors.		
Applicability	4.1. Transmission Service Provider. 4.2. Transmission Operator.	This reliability standard applies to: <ul style="list-style-type: none"> • ISO 		
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.	Ninety calendar days after the date of approval by the Commission.		
Requirement	R1. Each Transmission Operator shall select one of the methodologies ¹ listed below for calculating Available Transfer Capability (ATC) or Available	R1 The ISO must use the rated system path methodology, as described in Alberta reliability standard MOD-029-AB, for calculating available transfer capability for each interconnection in accordance with requirement R2 for those facilities within		RO – Steve Heidt

¹⁵ 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.

¹⁶ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	<p>Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]</p> <ul style="list-style-type: none"> • The Area Interchange Methodology, as described in MOD-028 • The Rated System Path Methodology, as described in MOD-029 • The Flowgate Methodology, as described in MOD-030 	the AIES.		
Measure		MR1 Evidence exists to show that one methodology has been selected for the calculation of available transfer capability.		
Requirement	<p>R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]</p>	<p>R2 The ISO must calculate available transfer capability values as listed below using the rated system path methodology as identified in MOD-029-AB:</p>		RO – Cam Bush

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference¹⁵	Comments¹⁶
Measure		MR2 Evidence exists to show that calculations of available transfer capability are performed for each of the time periods stated in requirement R2.1 through requirement R2.3.		
Requirement	R2.1. Hourly values for at least the next 48 hours.	R2.1 Hourly values for at least the next 48 hours.		RO – Cam Bush
Measure		MR2.1 Evidence exists to show that the methodology is implemented to produce values in time periods as specified in requirement R2.1.		
Requirement	R2.2. Daily values for at least the next 31 calendar days.	R2.2 Daily values for at least the next 31 calendar days.		RO – Cam Bush
Measure		MR2.2 – Evidence exists to show that the methodology is implemented to produce values in time periods specified in requirement R2.2.		
Requirement	R2.3. Monthly values for at least the next 12 months (months 2-13).	R2.3 Monthly values for the current month and at least the next 12 months.		RO – Cam Bush
Measure		MR2.3 Evidence exists to show that the methodology is implemented to produce values in time periods as specified in requirement R2.3.		
Requirement	R3. Each Transmission Service Provider shall prepare and keep current an Available Transfer	R3 The ISO must prepare and maintain, at minimum every two years, an available transfer capability implementation		RO – Steve Heidt

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	Capability Implementation Document (ATCID) that includes, at a minimum, the following information: [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]	document that includes, but is not limited to, the following:		
Measure		MR3 The available transfer capability implementation document exists and includes contents as specified in the sub-requirement R3.		
Requirement	R3.1. Information describing how the selected methodology (or methodologies) has been implemented, in such detail that, given the same information used by the Transmission Service Provider, the results of the ATC or AFC calculations can be validated.	R3.1 Information describing how the rated system path methodology has been implemented, in such detail that, given the same information used by the ISO, the results of the available transfer capability calculations can be validated.		RO – Steve Heidt (Cam Bush to provide input to ATCID)
Measure		MR3.1 Documentation exists that includes information at the level of detail as specified in requirement R3.1.		
Requirement	R3.2. A description of the manner in which the Transmission Service Provider will account for counterflows including:	R3.2 A description of the method by which the ISO accounts for counterflows including, but not limited to:		RO – Steve Heidt (Ron Smith to provide input to the ATCID)
Measure		MR3.2 Documentation exists that includes content as specified in requirement R3.2.		
Requirement	R3.2.1. How confirmed Transmission reservations, expected Interchange and internal counterflow are addressed in firm	R3.2.1 How confirmed transmission reservations, expected interchange and internal counterflow are addressed in firm and non-firm available transfer capability		RO – Steve Heidt (Ron Smith to provide input to the ATCID)

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	and non-firm ATC or AFC calculations.	calculations.		
Measure		MR3.2.1 Documentation exists that refers to and states how each condition is addressed as specified in requirement R3.2.1.		
Requirement	R3.2.2. A rationale for that accounting specified in R3.2.	R3.2.2 The ISO's rationale for the accounting of counterflows as specified in requirement R3.2.		RO – Steve Heidt (Ron Smith to provide input to the ATCID)
Measure		MR3.2.2 Documentation exists that includes a rationale for the treatment of counterflows.		
Requirement	R3.3. The identity of the Transmission Operators and Transmission Service Providers from which the Transmission Service Provider receives data for use in calculating ATC or AFC.	R3.3 The transmission operators external to Alberta, transmission service providers and TFOs, from whom the ISO receives data for use in calculating available transfer capability.		RO – Steve Heidt
Measure		MR3.3 Documentation exists that identifies all entities providing information for calculations as specified in requirement R3.3.		
Requirement	R3.4. The identity of the Transmission Service Providers and Transmission Operators to which it provides data for use in calculating transfer or Flowgate capability.	R3.4. The transmission service providers and transmission operators external to Alberta to whom the ISO provides data for use in calculating transfer or flowgate capability.		RO – Steve Heidt

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference¹⁵	Comments¹⁶
Measure		MR3.4 Documentation exists that identifies all entities providing information for calculations as specified in requirement R3.4.		
Requirement	R3.5. A description of the allocation processes listed below that are applicable to the Transmission Service Provider: <ul style="list-style-type: none"> • Processes used to allocate transfer or Flowgate capability among multiple lines or sub-paths within a larger ATC Path or Flowgate. • Processes used to allocate transfer or Flowgate capabilities among multiple owners or users of an ATC Path or Flowgate. • Processes used to allocate transfer or Flowgate capabilities between Transmission Service Providers to address issues such as forward looking congestion management and seams coordination. 	R3.5 A description of the following processes: <ul style="list-style-type: none"> • Processes to allocate transfer capability among multiple lines or sub-paths within a larger available transfer capability path. • Processes to allocate transfer capabilities among multiple owners or users of an available transfer capability path. • Processes to allocate transfer capabilities between transmission service providers to address issues such as forward looking congestion management and seams coordination. 		RO – Steve Heidt Ron Smith to provide input to the ATCID)
Measure		MR3.5 Documentation exists that includes content as specified in requirement R3.5.		
Requirement	R3.6. A description of how generation and transmission outages are considered in transfer or Flowgate capability	R3.6 How generating unit and transmission outages are considered in transfer capability calculations, including:		RO - Steve Heidt

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	calculations, including:			
Measure		MR3.6 – Documentation exists that includes content as specified in requirement R3.6.		
Requirement	R3.6.1. The criteria used to determine when an outage that is in effect part of a day impacts a daily calculation.	R3.6.1 The criteria used to determine when an outage that is in effect for part of a day, impacts a daily calculation.		RO - Steve Heidt
Measure		MR3.6.1 Documentation exists that includes content as specified in requirement R3.6.1.		
Requirement	R3.6.2. The criteria used to determine when an outage that is in effect part of a month impacts a monthly calculation.	R3.6.2. The criteria used to determine when an outage that is in effect for part of a month, impacts a monthly calculation.		RO - Steve Heidt
Measure		MR3.6.2. Documentation exists that includes content as specified in requirement R3.6.2.		
Requirement	R3.6.3. How outages from other Transmission Service Providers that can not be mapped to the Transmission model used to calculate transfer or Flowgate capability are addressed.	R3.6.3. How outages from other transmission service providers that cannot be mapped to the transmission model used to calculate transfer capability, are addressed.		RO - Steve Heidt
Measure		MR3.6.3 Documentation exists that includes content as specified in requirement R3.6.3.		
Requirement	R4. The Transmission Service Provider shall notify the following entities before implementing a new or revised ATCID: [<i>Violation Risk Factor: Lower</i>] [<i>Time</i>	R4. The ISO must notify the following entities before implementing a new or revised available transfer capability implementation document:		RO - Steve Heidt

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	<i>Horizon: Operations Planning]</i>			
Measure		MR4 Evidence exists to show that the appropriate entities were notified prior to the implementation of a new or revised available transfer capability implementation document.		
Requirement	R4.1. Each Planning Coordinator associated with the Transmission Service Provider's area.		The ISO performs this role in Alberta, so a notification is not necessary.	
Measure		NA		
Requirement	R4.2. Each Reliability Coordinator associated with the Transmission Service Provider's area.	R4.1 The WECC Reliability Coordinator.		RO - Steve Heidt
Measure		MR4.1 Evidence exists to show that the WECC Reliability Coordinator was notified prior to the implementation of a new or revised available transfer capability implementation document.		
Requirement	R4.3. Each Transmission Operator associated with the Transmission Service Provider's area.	R4.2 Each interconnected transmission operator adjacent to the AIES.		RO - Steve Heidt
Measure		MR4.2 Evidence exists to show that external transmission operators were notified prior to the implementation of a new or revised available transfer capability implementation document.		
Requirement	R4.4. Each Planning Coordinator adjacent to the Transmission Service Provider's area.	R4.3. Each planning coordinator adjacent to the AIES.		RO - Steve Heidt

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
Measure		MR4.3 Evidence exists to show that each planning coordinator was notified prior to the implementation of a new or revised available transfer capability implementation document.		
Requirement	R4.5. Each Reliability Coordinator adjacent to the Transmission Service Provider's area.	R4.4. Each reliability coordinator adjacent to the AIES.		RO - Steve Heidt
Measure		MR4.4 – Evidence exists to show that the reliability coordinator was notified prior to the implementation of a new or revised available transfer capability implementation document.		
Requirement	R4.6. Each Transmission Service Provider whose area is adjacent to the Transmission Service Provider's area.	R4.5. Each transmission service provider whose area is adjacent to the AIES.		RO - Steve Heidt
Measure		MR4.5 Evidence exists to show that transmission service providers were notified prior to the implementation of a new or revised available transfer capability implementation document.		
Requirement	R5. The Transmission Service Provider shall make available the current ATCID to all of the entities specified in R4. [<i>Violation Risk Factor: Lower</i>] [<i>Time Horizon: Operations Planning</i>]	R5. The ISO must make available the current available transfer capability implementation document to all of the entities specified in requirement R4.		RO - Steve Heidt
Measure		MR5 Evidence exists to show that the document is available to all entities as specified in requirement R4.		
Requirement	R6. When calculating Total	R6 The ISO must, when calculating total		RO – Cam Bush

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	Transfer Capability (TTC) or Total Flowgate Capability (TFC) the Transmission Operator shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>	transfer capability, use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period.		
Measure		<p>MR6 Documented assumptions identifies that assumptions used in the calculation are within the limits as specified in requirement R6.</p> <p>Documented assumptions such as contingencies, loop flow, generation re-dispatch, switching operations guides or data sources for load forecast and facility outages, and modeling data such as operations planning studies, models, show that total transfer capability is calculated as specified in requirement R6.</p>		
Requirement	R7. When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning		The ISO performs both roles in Alberta as identified in NERC requirements R6 and R7.	

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	of operations has been performed for that time period. <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>			
Measure		NA		
Requirement	R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i>	R7 The ISO must recalculate available transfer capability at a minimum on the following frequency, unless none of the calculated values identified in the available transfer capability equation have changed:		RO – Cam Bush
Measure		MR7 Evidence exists to show that the available transfer capacity is calculated in accordance with the frequencies defined in requirement R7.1 through requirement R7.3.		
Requirement	R8.1. Hourly values, 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 ATC equation.	R7.1 Hourly values, once per hour. The ISO is 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 available transfer capability equation.		RO – Cam Bush
Measure		MR7.1 Evidence such as logs exist to show that calculations were performed hourly as specified in requirement R7.1.		
Requirement	R8.2. Daily values, once per day.	R7.2. Daily values, once per day.		RO – Cam Bush

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
Measure		MR7.2 Evidence such as logs exist to show that calculations were performed daily as specified in requirement R7.2.		
Requirement	R8.3. Monthly values, once per week.	R7.3 Monthly values, once per week.		RO – Cam Bush
Measure		MR7.3 Evidence such as logs exist to show that calculations were performed monthly as specified in requirement R7.3.		
Requirement	<p>R9. Within thirty calendar days of receiving a request by any Transmission Service Provider, Planning Coordinator, Reliability Coordinator, or Transmission Operator for data from the list below solely for use in the requestor's ATC or AFC calculations, each Transmission Service Provider receiving said request shall begin to make the requested data available to the requestor, subject to the conditions specified in R9.1 and R9.2: <i>[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</i></p> <ul style="list-style-type: none"> • Expected generation and Transmission outages, additions, and retirements. • Load forecasts. • Unit commitments and order of dispatch, to include all designated network resources 	<p>R8 The ISO must make the data described below, available to interconnected transmission operators, transmission service providers, planning coordinators or reliability coordinators upon request, within 30 days of receiving the request: provided that the ISO must be satisfied that the data will be used solely for available transfer capability or available flowgate capability calculations.</p> <p>The data described below must be provided, for up to the next 13 months, in accordance with the conditions specified in requirements R8.1 and requirement R8.2.</p> <ul style="list-style-type: none"> • Sensitivities to generation outages and approved and tentative transmission, generator and transmission additions, and retirements. • Load forecasts. • Generating unit commitments and order of dispatch include all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected 		<p>RO –Steve Heidt and Cam Bush</p> <p>Recommend requirement R8 and the sub-requirements be restructured.</p>

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference¹⁵	Comments¹⁶
	<p>and other resources that are</p> <p>Note that the North American Energy Standards Board (NAESB) is developing the companion standards that address the posting of ATC information, including supporting information such as that described in R9.</p> <p>committed or have the legal obligation to run, as they are expected to run, in one of the following formats chosen by the data provider:</p> <ul style="list-style-type: none"> • Dispatch Order • Participation Factors • Block Dispatch • Aggregated firm capacity set-aside for Network Integration Transmission Service and aggregated non-firm capacity set aside for Network Integration Transmission Service (i.e. Secondary Service). • Firm and non-firm Transmission reservations. • Aggregated capacity set-aside for Grandfathered obligations 	<p>to run, in one of the following formats chosen by the data provider:</p> <ul style="list-style-type: none"> – dispatch order – participation factors – block dispatch – aggregated firm capacity set aside for network integration transmission service and aggregated non-firm capacity set aside for network integration transmission service such as secondary service – firm and non-firm transmission reservations – aggregated capacity set aside for grandfathered obligations – firm roll-over rights. – any firm and non-firm adjustments applied by the transmission service provider to reflect parallel path impacts – power flow models and underlying assumptions – contingencies, provided in one or more of the following formats: <ul style="list-style-type: none"> ○ a list of elements ○ a list of flowgates ○ a set of selection criteria that can be applied to the transmission model used by the transmission operator and/or transmission service provider 		

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference¹⁵	Comments¹⁶
	<ul style="list-style-type: none"> • Firm roll-over rights. • Any firm and non-firm adjustments applied by the Transmission Service Provider to reflect parallel path impacts. • Power flow models and underlying assumptions. • Contingencies, provided in one or more of the following formats: <ul style="list-style-type: none"> • A list of Elements • A list of Flowgates • A set of selection criteria that can be applied to the Transmission model used by the Transmission Operator and/or Transmission Service Provider • Facility Ratings. • Any other services that impact Existing Transmission Commitments (ETCs). • Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) for all ATC Paths or Flowgates. • Values of Total Flowgate Capability (TFC) and AFC for any Flowgates considered by the Transmission Service 	<ul style="list-style-type: none"> ○ facility ratings ○ any other services that impact existing transmission commitments ○ values of capacity benefit margin and transmission reliability margin for all available transfer capability paths or flowgates ○ values of total flowgate capability and available flowgate capability for any flowgates considered by the transmission service provider receiving the request when selling transmission service ○ values of total transfer capability and available transfer capability for all available transfer capability paths for those transmission service providers receiving the request that do not consider flowgates when selling transmission service ○ source and sink identification and mapping to the model 		

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	<p>Provider receiving the request when selling Transmission service.</p> <ul style="list-style-type: none"> • Values of TTC and ATC for all ATC Paths for those Transmission Service Providers receiving the request that do not consider Flowgates when selling Transmission Service. • Source and sink identification and mapping to the model. 			
Measure		MR8 Evidence such as logs or confirmation letters exists to show that each data item is being submitted within 30 calendar days of a request as specified in requirement R8.		
Requirement	R9.1. The Transmission Service Provider shall make its own current data available, in the format maintained by the Transmission Service Provider, for up to 13 months into the future (subject to confidentiality and security requirements).	R8.1 The data must be provided in the format maintained by the ISO, subject to ISO confidentiality and security requirements.		RO – Steve Heidt
Measure		MR8.1 Evidence such as logs or confirmation letters exists to show that the ISO has provided data as specified in R8.1.		
Requirement	R9.1.1. If the Transmission Service Provider uses the data requested in its transfer or	R8.1.1 If the ISO uses the data requested in its transfer capability calculations, it must make the data used available.		RO – Steve Heidt

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	Flowgate capability calculations, it shall make the data used available			
Measure		M8.1.1 Evidence such as logs or confirmation letters exists to show that the ISO has provided data as specified in requirement R8.1.1.		
Requirement	R9.1.2. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, but maintains that data, it shall make that data available	R8.1.2 If the ISO does not use the data requested in its transfer capability calculations, but maintains that data, it must make that data available.		RO – Steve Heidt
Measure		M8.1.2 Evidence such as logs or confirmation letters exists to show that the ISO has provided data as specified in requirement R8.1.2.		
Requirement	R9.1.3. If the Transmission Service Provider does not use the data requested in its transfer or Flowgate capability calculations, and does not maintain that data, it shall not be required to make that data available	R8.1.3 If the ISO does not use the data requested in its transfer capability calculations, and does not maintain that data, it is not required to make that data available.		RO – Steve Heidt
Measure		M8.1.3 Evidence such as logs or confirmation letters exists to show that the ISO has provided data as specified in requirement R8.1.3.		
Requirement	R9.2. This data shall be made available by the Transmission Provider on the schedule specified by the requestor (but no	R8.2. This data must be made available by the ISO on the schedule specified by the requestor, but no more frequently than once per hour, unless mutually agreed		RO – Steve Heidt

ARC AESO Internal Work Group Assessment and Conversion of NERC MOD-001-1 to Alberta MOD-001-AB-1 Available Transmission System Capability				
Section	NERC MOD-001-1	Alberta MOD-001-AB-1	Reason for Difference ¹⁵	Comments ¹⁶
	more frequently than once per hour, unless mutually agreed to by the requester and the provider).	upon by the requester and the provider.		
Measure		M8.2 Evidence such as logs or confirmation letters exists to show that the ISO has provided data with the frequency as specified in requirement R8.2.		
Compliance	To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/MOD-001-1.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)

- Alberta Interconnected Electric System (AIES)
- available transfer capability
- capacity benefit margin
- Commission
- contingencies
- day
- elements
- facilities
- facility ratings
- firm
- interchange
- interconnection
- ISO
- load
- outage
- reliability standard
- transmission facility owner (TFO)
- transmission operators
- transmission reliability margin
- transmission service providers
- total transfer capability
- WECC

Standard Owner:

Jerry Mossing, Director – Transmission Support

AESO Requirement Owner(s):

Steve Heidt, Technical Resource Manager for requirements R1, R3, R4, R5, R8 (shared with Cam Bush), R8.1 and R8.2.

Cam Bush, Manager – Operations Coordination for requirements R2, R6, R7 and R8 (shared with Steve Heidt).

AESO Subject Matter Expert(s):

AESO Reliability Committee (ARC) Agenda - Continued

Steve Heidt, Technical Resource Manager
Cam Bush, Manager – Operations Coordination

Work Group Comments:

No outstanding comments or concerns.

Work Group Response:

None required.

Work Group Recommendation:

The OWG members support the recommendation to submit this reliability standard to the ARC.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	OWG member
Steve Heidt	AESO	Requirement owner
Ron Smith	AESO	Requirement owner
Ken Gardner	AESO	Reliability Standards Technical Specialist
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Larry Kram	AESO	Legal review
Don Olson	AESO	OWG member
John Walker	ATCO Power	OWG member
Dwayne Aasberg	Dow Chemical	OWG member
Terri Haffick	ENMAX	OWG member
Anirban Bosu	TransAlta	OWG member
Dan Bamber	TransAlta	OWG member
Blaine Beisiegel	ATCO Electric	OWG member
John Kehler	AESO	OWG member
Rick Spyker	ALTALINK	OWG member
Kevin Neithercut	ENMAX	OWG member

AESO Reliability Committee (ARC) Agenda - Continued

Name	Organization	Role
Mark Thompson	AESO	OWG member
Doug Hincks	AESO	OWG Chair
Michael Taylor	Capital Power	OWG member
Blaise Smith	TransAlta	OWG member
Stew Purkis	City of Lethbridge	OWG member
Travis Robinson	EPCOR	OWG member
Peter Bartsch	AltaLink	OWG member
Roy Hanson	ENMAX Generation	OWG member
Amber Kirby	Capital Power Corp	OWG member
Subrota Bairagi	Suncor	OWG member

ARC Operation Work Group Assessment and Conversion of NERC MOD-024-1 to Alberta MOD-024-AB-1				
Verification of Generator Gross and Net Real Power Capability				
Section	NERC MOD-024-1	Alberta MOD-024-AB-1	Reason for Difference ¹⁷	Comments ¹⁸
Purpose	To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The purpose of this reliability standard is to ensure accurate information on generating unit gross real power and net real power capability is reported to the ISO.		Note this std is about stating and verifying values. What those values should be are covered under the G&L and wind standards and/or the PPA's.
Applicability	<p>4.1. Regional Reliability Organization.</p> <p>4.2. Generation Owner.</p>	<p>This reliability standard applies to:</p> <ul style="list-style-type: none"> • ISO • GFOs with generating facilities connected to the transmission system that consists of either: <ul style="list-style-type: none"> (a) a generating unit with a maximum authorized real power rating of 9 MW or greater; or (b) an aggregated generating facility with a maximum authorized real power rating of 18 MW or greater 		<p>9 MW = 10 MVA @ .9 pf. 10 MVA is the value referred to in the WECC (WSCC) document Synchronous Machine Reactive Capability Verification, 1996. and the WECC Generating Unit Model Validation Policy</p> <p>Consider using 18 MW (20 MVA) as the WECC Generating Unit Model Validation Policy uses 20 MVA for aggregated facilities.</p>
Effective Date	Requirement 1 and Requirement 2 — April 1, 2006.	Ninety calendar days after the date of approval by the Commission.		The AESO is using the WECC Testing Policy as the basis for

¹⁷ 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.

¹⁸ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC Operation Work Group Assessment and Conversion of NERC MOD-024-1 to Alberta MOD-024-AB-1				
Verification of Generator Gross and Net Real Power Capability				
Section	NERC MOD-024-1	Alberta MOD-024-AB-1	Reason for Difference ¹⁷	Comments ¹⁸
	Requirement 3 — January 1, 2007.			<p>implementing this standard. The following is an excerpt from the WECC Generator Testing Policy Implementation – Cover letter...</p> <p><i>Issue 2: A large number of Generator Owners, who complied with the original baseline test requirement, are required to perform model re-validation. Many of the Owners have multiple generating facilities. From resource management standpoint, the Owners should be allowed to spread generator re-validation over a five-year period. Many Generator Owners are in the midst of the equipment replacement programs. It makes sense to coordinate the re-validation efforts with the respective replacement programs, as well as maintenance cycles. On the other hand, WECC should have the authority to accept or reject the re-validation schedule proposed by the Generator Owners.</i></p>

ARC Operation Work Group Assessment and Conversion of NERC MOD-024-1 to Alberta MOD-024-AB-1				
Verification of Generator Gross and Net Real Power Capability				
Section	NERC MOD-024-1	Alberta MOD-024-AB-1	Reason for Difference ¹⁷	Comments ¹⁸
				<p><i>Generator Owners that have complied with the baseline test requirements (as defined in section B.1.2 of the Policy) shall provide to WECC staff, by December 31, 2006, a schedule to perform model re-validation (as defined in section B.1.3 of the Policy). The Generator Owner should coordinate the schedule with the appropriate Transmission Planner(s). The Generator Owner will be considered compliant with the Policy as long as the initial model re-validation is completed within 5 years from December 31, 2006.</i></p> <p><i>Subsequent model re-validation should be done every 5 years.</i></p>
Requirement	<p>R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:</p>		<p>This requirement is a WECC responsibility.</p>	

ARC Operation Work Group Assessment and Conversion of NERC MOD-024-1 to Alberta MOD-024-AB-1 Verification of Generator Gross and Net Real Power Capability				
Section	NERC MOD-024-1	Alberta MOD-024-AB-1	Reason for Difference ¹⁷	Comments ¹⁸
Measure	M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Real Power capability in accordance with R1.			

Requirement	R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.			<p>WECC does have an exemption criteria Section B.4 of the Generating Unit Model Validation Policy states:</p> <p><i>B.4.1. WECC may grant exemptions to the Generator Owners in rare situations where a unique condition or equipment configuration exists that would preclude or delay testing and model data validation.</i></p> <p><i>B.4.2. The Generator Owner may request an exemption by submittal to WECC through the Transmission Planner. The request shall include justification for the exemption. WECC shall respond to the request within 90 days after receipt.</i></p>
Measure				
Requirement	R1.2. Criteria for reporting generating unit auxiliary loads.			
Measure				
Requirement	R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.			

Measure				
Requirement	R1.4. Periodicity and schedule of model and data verification and reporting.			
Measure				
Requirement	R1.5. Information to be verified and reported:			
Measure				
Requirement	R1.5.1. Seasonal gross and net Real Power generating capabilities.			
Measure				
Requirement	R1.5.2. Real power requirements of auxiliary loads.			
Measure				
Requirement	R1.5.3. Method of verification, including date and conditions.			
Measure				
Requirement	R2. The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.		This requirement is a WECC responsibility.	
Measure	M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to those procedures, for verification and reporting of generator gross and net Real Power capability were provided to affected Generator Owners,			

AESO Reliability Committee (ARC) Agenda - Continued

	Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.			
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<p>Requirement</p>	<p>R3. The Generator Owner shall follow its Regional Reliability Organization’s procedures for verifying and reporting its gross and net Real Power generating capability per R1.</p>	<p>R1 Each GFO must comply with the procedures published by the ISO for verifying and reporting its gross and net real power generating capability. In the absence of a procedure developed by the ISO, each GFO must comply with the procedures published by the WECC.</p> <p>R2 The ISO procedures for verifying and reporting generating unit gross and net real power generating capability must, if developed, be equal to or more reliable than the procedures for such verification and reporting as established by the WECC.</p>	<p>Capital Power is concerned about the implementation of this standard within the Alberta market and implications to PPAs.</p> <p>The ISO advises that we have been performing this for several years.</p> <p>Capital Power is also concerned about revisions to the WECC documents that have direct implications to generators. Also concerned about the change management process and opportunity for stakeholder input.</p> <p>In order to comment on WECC standards Capital Power would need to become a WECC member.</p>	<p>Below are applicable WECC procedures:</p> <p>1. “Synchronous Machine Reactive Limits Verification” ... http://www.wecc.biz/library/WECC%20Documents/Documents%20for%20Generators/Generator%20Testing%20Program/Synchronous%20Machine%20Reactive%20Limits%20Verification.pdf</p> <p>2. “Facility Data Requirements” document. Access this document by following this link: http://www.wecc.biz/library/WECC%20Documents/Forms/AllItems.aspx?RootFolder=%2fLibrary%2fWECC%20Documents%2fDocuments%20for%20Generators%2fGenerator%20Testing%20Program&FolderCTID=%2f61959662-7baf-8e62-572d-3eb92d4a212d88532d6477737956b47d</p> <p>And then open the following folders and documents:</p> <ul style="list-style-type: none"> • “2006 Generator Test Policy” folder • “2006 Generator Test Program” • “Facility Data Requirements”
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<p>Measure</p>	<p>M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Real Power capability, consistent with that Regional Reliability Organization’s procedures.</p>	<p>MR1 Confirmation exists that the data provided is complete for each GFO’s generating unit and is consistent with the procedures established as specified in requirement R1 subject to the following:</p> <p>GFO’s with facilities that are in operation on the effective date of this reliability standard will be considered compliant provided that a valid WECC model validation report complete with a Reactive Limits Verification test has been submitted in the past 5 years and future verification will then be required as part of the 5 year model validation cycle.</p> <p>.</p> <p>MR2 Where ISO procedures exist as specified in requirement R2, these procedures are equal to or more reliable than the procedures for such verification and reporting as established by the WECC.</p>	<p>MR1. Confirmation exists that the data provided is complete for each GFO’s generating unit and is consistent with the procedures established as specified in requirement R1.</p> <p>MR2 Where ISO procedures exist as specified in requirement R2, these procedures are substantially consistent with the procedures for such verification and reporting as established by the WECC.</p>	<p>The AESO is considering if this is the appropriate place to include the information in the subject to clause in measure MR1.</p>
<p>Compliance</p>	<p>To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/MOD-024-1.pdf</p>		<p>There is no compliance section currently proposed in the Alberta Reliability Standards. This approach is deemed consistent with the existing ISO Rules.</p>	
<p>Regional Differences</p>	<p>None identified.</p>		<p>Not applicable in Alberta</p>	

Proposed Terms for the ARS Glossary¹⁹:

“**collector bus**” means the low voltage side of any step-up transformers connected to the **transmission system** where the **real power** and **reactive power** produced by any **generating units** or **reactive power** resources, or both of them, are collected.

“**gross real power**” means;

- (i) for **aggregated generating facilities** with one or more **collector busses**, the sum of the **real power** delivered by the **generating units** measured at those **collector busses**;
- (ii) for **aggregated generating facilities** without a **collector bus**, a **real power** measurement at the generator terminal for each **generating unit**; or
- (iii) for a **generating unit** that is not part of an **aggregated generating facility**, the **real power** measurement at the generator terminal.

“**net real power**” means for an **aggregated generating facility** or a **generating unit**, the sum of **real power** measurements at the high voltage side of all step-up transformers directly connected to the **transmission system**.

Existing Defined Terms Used in this Standard:

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

- bulk electric system (BES)
- Commission
- day
- generating facility owner (GFO)
- generating unit
- gross real power
- ISO
- net real power
- reliability
- reliability standard
- Western Electric Coordinating Council (WECC)

Standard Owner:

Jerry Mossing, Director, Transmission Support

¹⁹ These proposed defined terms are also being consulted on as part of the ISO rules consultation on Section G1 Definitions (Package 4).

AESO Requirement Owner(s):

John Kehler is the requirement owner for R2.

AESO Subject Matter Expert(s):

John Kehler, Technical Lead – System Performance
Kevin Wiens, Analyst – System Performance
Pamela Mclean, Technical Lead - Power System Model Management
Galen Lam, Technical Specialist, Long Term Planning

Work Group Comments:

Request the document on what “confirmation” means as developed by AESO Compliance group to be sent to the OWG members.

The OWG work group members recommend to AESO compliance to include documentation (possibly in the compliance monitoring program or RSAW) that data is to be provided after the effective date and is not retroactive to previous tests and data submissions. Also, that there would not be a requirement to advance re-testing to meet new requirements.

AESO Response:

The AESO will provide information to clarify to the OWG members what “confirmation” means in the measures.
Refer to proposed amendment to measure MR1.

Work Group Recommendation:

The OWG members support the recommendation to submit this reliability standard to the ARC.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	OWG - Chair
Doug Hincks	AESO	OWG - Alternate Chair (preliminary review)
John Kehler	AESO	Subject Matter Expert
Ken Gardner	AESO	Reliability Standards Technical Specialist
Don Olson	AESO	OWG member (preliminary review)
Larry Kram	AESO	Legal review

AESO Reliability Committee (ARC) Agenda - Continued

Elizabeth Olivier	Consultant	Technical Writer review
John Walker	ATCO Power	OWG member
Dwayne Aasberg	Dow Chemical	OWG member
Terri Haffick	ENMAX	OWG member
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 (preliminary review)
Mark Thompson	AESO	OWG member
Michael Taylor	Capital Power	OWG member
Kevin Wiens	AESO	Subject Matter Expert
Peter Wong	AESO	Compliance measures
Pamela McLean	AESO	Subject Matter Expert
Galen Lam	AESO	Subject Matter Expert
Subrota Bairagi	Suncor	OWG member
Blaise Smith	TransAlta	OWG member
Roy Hanson	ENMAX Generation	OWG member
Stew Purkis	City of Lethbridge	OWG member
Amber Kirby	Capital Power Corp.	OWG member
Peter Bartsch	AltaLink	OWG member

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1				
Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference ²⁰	Comments ²¹
Purpose	To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.	The purpose of this reliability standard is to ensure accurate information on generating unit gross reactive power and net reactive power capability is reported to the ISO.		
Applicability	<p>4.1. Regional Reliability Organization.</p> <p>4.2. Generation Owner.</p>	<p>This reliability standard applies to:</p> <ul style="list-style-type: none"> • ISO • GFOs with generating facilities connected to the transmission system that consists of either: <ul style="list-style-type: none"> (c) a generating unit with a maximum authorized real power rating of 9 MW or greater; or (d) an aggregated generating facility with a maximum authorized real power rating of 18 MW or greater 		<p>9 MW = 10 MVA @ .9 pf. 10 MVA is the value referred to in the WECC (WSCC) document Synchronous Machine Reactive Capability Verification, 1996. and the WECC Generating Unit Model Validation Policy</p> <p>Consider using 18 MW (20 MVA) as the WECC Generating Unit Model Validation Policy uses 20 MVA for aggregated facilities.</p>
Effective Date	Requirement 1 and Requirement 2 — January 1, 2007 Requirement 3: January 1, 2008 — 1st 20%	Ninety calendar days after the date of approval by the Commission.		The AESO is using the WECC Testing Policy as the basis for implementing this

²⁰ 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.

²¹ Including the identification of issues, compliance ideas and identification of exempt entities.

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1				
Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference ²⁰	Comments ²¹
	compliant January 1, 2009 — 2nd 20% compliant January 1, 2010 — 3rd 20% compliant January 1, 2011 — 4th 20% compliant January 1, 2012 — 5th 20% compliant			standard. The following is an excerpt from the WECC Generator Testing Policy Implementation – Cover letter... <i>Issue 2: A large number of Generator Owners, who complied with the original baseline test requirement, are required to perform model re-validation. Many of the Owners have multiple generating facilities. From resource management standpoint, the Owners should be allowed to spread generator re-validation over a five-year period. Many Generator Owners are in the midst of the equipment replacement programs. It makes sense to coordinate the re-validation efforts with the respective replacement programs, as well as maintenance cycles. On the other hand, WECC should have the authority to</i>

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1				
Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference ²⁰	Comments ²¹
				<p><i>accept or reject the re-validation schedule proposed by the Generator Owners.</i></p> <p><i>Generator Owners that have complied with the baseline test requirements (as defined in section B.1.2 of the Policy) shall provide to WECC staff, by December 31, 2006, a schedule to perform model re-validation (as defined in section B.1.3 of the Policy). The Generator Owner should coordinate the schedule with the appropriate Transmission Planner(s). The Generator Owner will be considered compliant with the Policy as long as the initial model re-validation is completed within 5 years from December 31, 2006.</i></p> <p><i>Subsequent model re-validation should be done every 5 years.</i></p>
Requirement	R1. The Regional Reliability		This requirement is a WECC	

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1 Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference ²⁰	Comments ²¹
	Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:		responsibility.	
Measure	M1. The Regional Reliability Organization shall have available for inspection the procedures for the verification and reporting of generator gross and net Reactive Power capability in accordance with R1.			
Requirement	R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.			
Measure				
Requirement	R1.2. Criteria for reporting generating unit auxiliary loads.			
Measure				
Requirement	R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc.			
Measure				
Requirement	R1.4. Periodicity and schedule of			

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1 Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference ²⁰	Comments ²¹
	model and data verification and reporting.			
Measure				
Requirement	R1.5. Information to be reported:			
Measure				
Requirement	R1.5.1. Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.			
Measure				
Requirement	R1.5.2. Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.			
Measure				
Requirement	R1.5.3. Verified Reactive Power of auxiliary loads.			
Measure				
Requirement	R1.5.4. Method of verification, including date and conditions.			
Measure				
Requirement	R2. The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators,		This requirement is a WECC responsibility.	

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1 Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference ²⁰	Comments ²¹
	Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.			
Measure	M2. The Regional Reliability Organization shall have evidence that its procedures, and any revisions to these procedures, for verification and reporting of generator gross and net Reactive Power capability were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.			
Requirement	R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.	<p>R1 Each GFO must comply with the procedures published by the ISO for verifying and reporting its gross and net reactive power generating capability. In the absence of a procedure developed by the ISO, each GFO must comply with the procedures published by the WECC.</p> <p>R2 The ISO procedures for verifying and reporting generating unit gross and net reactive power generating capability must, if developed, be equal to or more reliable than the procedures for</p>		<p>Below are applicable WECC procedures:</p> <p>1. "Synchronous Machine Reactive Limits Verification"... http://www.wecc.biz/library/WECC%20Documents/Documents%20for%20Generators/Generator%20Testing%20Program/Synchronous%20Machine%20Reactive%20Limits%20Verification.pdf</p>

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1 Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference ²⁰	Comments ²¹
		such verification and reporting as established by the WECC.		<p>2. "Facility Data Requirements" document. Access this document by following this link: http://www.wecc.biz/library/WECC%20Documents/Forms/AllItems.aspx?RootFolder=%2flibrary%2fWECC%20Documents%2fDocuments%20for%20Generators%2fGenerator%20Testing%20Program&FolderCTID=%7bAF8E6257%2d3EB9%2d4A21%2d8853%2d6477737956B4%7d</p> <p>And then open the following folders and documents:</p> <ul style="list-style-type: none"> • "2006 Generator Test Policy" folder • "2006 Generator Test Program" • "Facility Data Requirements"

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1 Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference ²⁰	Comments ²¹
Measure	<p>M3. The Generator Owner shall have evidence it provided verified information of its generator gross and net Reactive Power capability, consistent with that Regional Reliability Organization's procedures.</p>	<p>MR1. Confirmation exists that the data provided is complete for each GFO's generating unit and is consistent with the procedures established as specified in requirement R1 subject to the following:</p> <p>GFO's with facilities that are in operation on the effective date of this reliability standard will be considered compliant provided that a valid WECC model validation report complete with a Reactive Limits Verification test has been submitted in the past 5 years and future verification will then be required as part of the 5 year model validation cycle.</p> <p>MR2 Where ISO procedures exist as specified in requirement R2, these procedures are equal to or more reliable than the procedures for such verification and reporting as established by the WECC.</p>		<p>The AESO is considering if this is the appropriate place to include the information in the subject to clause in measure MR1.</p>
Compliance	<p>To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/MOD-025-1.pdf</p>		<p>There is no compliance section currently proposed in the Alberta Reliability Standards. This approach is deemed consistent with the existing ISO Rules.</p>	

ARC Operation Work Group Assessment and Conversion of NERC MOD-025-1 to Alberta MOD-025-AB-1 Verification of Generator Gross and Net Reactive Power Capability				
Section	NERC MOD-025-1	Alberta MOD-025-AB-1	Reason for Difference²⁰	Comments²¹
Regional Differences	None identified.		Not applicable in Alberta	

Proposed Terms for the ARS Glossary²²:

“**collector bus**” means the low voltage side of any step-up transformers connected to the **transmission system** where the **real power** and **reactive power** produced by any **generating units** or **reactive power** resources, or both of them, are collected.

gross reactive power” means:

- (i) for **aggregated generating facilities** with one or more **collector busses**, the sum of the **reactive power** flows from the **generating units** or **reactive power** resources or both of them measured at those **collector busses**;
- (ii) for **aggregated generating facilities** without a **collector bus**, a **reactive power** measurement at the generator terminal for each **generating unit**; or
- (iii) for a **generating unit** that is not part of an **aggregated generating facility**, the **reactive power** measurement at the generator terminal.

“**net reactive power**” means for an **aggregated generating facility** or a **generating unit**, the sum of **reactive power** measurements at the high voltage side of all step-up transformers directly connected to the **transmission system**.

Existing Defined Terms Used in this Standard:

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

- bulk electric system (BES)
- Commission
- day
- generating facility owner (GFO)
- generating unit
- ISO
- reliability
- reliability standard

Western Electric Coordinating Council (WECC)

Standard Owner:

Jerry Mossing, Director, Operations Planning

AESO Requirement Owner(s):

John Kehler is the requirement owner for R2.

AESO Subject Matter Expert(s):

²²These proposed defined terms are also being consulted on as part of the ISO rules consultation on Section G1 Definitions (Package 4).

John Kehler, Technical Lead – System Performance
 Kevin Wiens, Analyst – System Performance
 Pamela Mclean, Technical Lead - Power System Model Management
 Galen Lam, Technical Specialist, Long Term Planning

Work Group Comments:

The OWG members recommend to AESO compliance to include documentation (possibly in the compliance monitoring program or RSAW) that data is to be provided after the effective date and is not retroactive to previous tests and data submissions. Also, that there would not be a requirement to advance re-testing to meet new requirements.

AESO Response:

Refer to proposed amendment to measure MR1.

Work Group Recommendation:

The OWG members support the recommendation to submit this reliability standard to the ARC.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	OWG - Chair
Doug Hincks	AESO	OWG - Alternate Chair (preliminary review)
John Kehler	AESO	Subject Matter Expert
Ken Gardner	AESO	Reliability Standards Technical Specialist
Don Olson	AESO	OWG member (preliminary review)
Larry Kram	AESO	Legal review
Elizabeth Olivier	Consultant	Technical Writer review
John Walker	ATCO Power	OWG member
Dwayne Aasberg	Dow Chemical	OWG member
Terri Haffick	ENMAX	OWG member
Anirban Bosu	TransAlta	OWG member
Dan Bamber	TransAlta	OWG member
Blaine Beisiegel	ATCO Electric	OWG member

AESO Reliability Committee (ARC) Agenda - Continued

Rick Spyker	AltaLink	OWG member
Kevin Neithercut	ENMAX	OWG member (preliminary review)
Mark Thompson	AESO	OWG member
Michael Taylor	Capital Power	OWG member
Kevin Wiens	AESO	Subject Matter Expert
Peter Wong	AESO	Compliance measures
Pamela McLean	AESO	Subject Matter Expert
Galen Lam	AESO	Subject Matter Expert
Subrota Bairagi	Suncor	OWG member
Blaise Smith	TransAlta	OWG member
Roy Hanson	ENMAX Generation	OWG member
Stew Purkis	City of Lethbridge	OWG member
Amber Kirby	Capital Power Corp.	OWG member
Peter Bartsch	AltaLink	OWG member

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
Purpose	To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.	The purpose of this reliability standard is to increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the rated system path methodology to support analysis and system operations.		
Applicability	<p>4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.</p> <p>4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.</p>	<p>This reliability standard applies to:</p> <ul style="list-style-type: none"> • ISO 		
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-	Ninety calendar days after the date of approval by the Commission.		

²³ 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.

²⁴ Including the identification of issues, compliance ideas and identification of exempt entities.

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	030-1) are approved by all applicable regulatory authorities.			
Requirement	R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]	R1 The ISO must, when calculating total transfer capability for available transfer capability paths, use a transmission model which meets the following requirements:		
Measure	M1. Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1) M1.1. Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)	MR1 Evidence such as an engineering report exists and shows that the report is based on the model used to calculate available transfer capability.		
Requirement	R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:	R1.1 Uses data and assumptions consistent with the time period being studied and at a minimum meets the following criteria:		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
Measure	M1.2. The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)	MR1.1 Evidence such as an engineering report exists and shows that data and assumptions are applicable to the time period when the model is to be used.		
Requirement	R1.1.1. Includes at least:			
Measure				
Requirement	R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.	R1.1.1. The ISO's balancing authority area, and with respect to radial lines and facilities 161kV or below, an equivalent representation.		
Measure		MR1.1.1 Evidence such as statements in an engineering report exists and shows that the model includes the ISO's entire balancing area, and is modeled as specified in requirement R1.1.1.		
Requirement	R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)	R1.1.2 All interconnected transmission operator areas interconnected with the ISO's balancing authority area, or an equivalent representation.		
Measure		MR1.1.2 Evidence such as statements in an engineering report exists and shows that areas are included in the model as specified in requirement R1.1.2.		
Requirement	R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint	R1.1.3 Any other interconnected transmission operator area linked to the ISO's balancing authority area by a joint operating agreement, or an equivalent		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	operating agreement. (Equivalent representation is allowed.)	representation.		
Measure		MR1.1.3 Evidence such as statements in an engineering report exists and shows that areas are included in the model as specified in requirement R1.1.3.		
Requirement	R1.1.2. Models all system Elements as in-service for the assumed initial conditions.	R1.1.4 Uses all system elements, transmission lines and transformers that are normally in service, as in service for the assumed initial conditions.	Reflects actual transmission system configuration and does not include elements that are normally out of service.	
Measure		MR1.1.4 Evidence such as statements in an engineering report exists and shows that requirement R1.1. 4 is modeled accurately.		
Requirement	R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.	R1.1.5 Uses all generation, which may be a single generating unit or multiple generating units that are greater than 20 MVA at the point of interconnection in the studied area.		
Measure		MR1.1.5 Evidence such as statements in an engineering report exists and shows that requirement R1.1.5 is modeled accurately.		
Requirement	R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability	R1.1.6 Uses phase shifters in non-regulating mode, unless otherwise specified in the available transfer capability implementation document, as		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	Implementation Document (ATCID).	referred to in MOD-001-AB.		
Measure		MR1.1.6 Evidence such as statements in an engineering report exists and shows that requirement R1.1.6 is modeled accurately.		
Requirement	R1.1.5. Uses Load forecast by Balancing Authority.	R1.1.7 Uses ISO's balancing authority area load forecast.		
Measure		MR1.1.7 Evidence such as statements in an engineering report exists and shows that requirement R1.1.7 is modeled accurately.		
Requirement	R1.1.6. Uses Transmission Facility additions and retirements.	R1.1.8 Uses transmission facility additions and retirements.		
Measure		MR1.1.8 Evidence such as statements in an engineering report exists and shows that requirement R1.1.8 is modeled accurately.		
Requirement	R1.1.7. Uses Generation Facility additions and retirements.	R1.1.9 Uses generating unit additions and retirements.		
Measure		MR1.1.9 Evidence such as statements in an engineering report exists and shows that requirement R1.1.9 is modeled accurately.		
Requirement	R1.1.8. Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.	R1.1.10 Uses remedial action schemes or considers the effects of remedial action schemes in models where currently existing or projected for implementation within the studied time		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
		horizon.		
Measure		MR1.1.10 Evidence such as statements in an engineering report exists and shows that requirement R1.1.10 is modeled accurately.		
Requirement	R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.	R1.1.11 Uses series compensation for each transmission line that has series compensation, at the expected operating level unless specified otherwise in the available transfer capability implementation document, as referenced in MOD-001-AB.		
Measure		MR1.1.11 Evidence such as statements in an engineering report exists and shows that requirement R1.1.11 is modeled accurately.		
Requirement	R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.	R1.1.12 Includes any other modeling requirements or criteria specified in the available transfer capability implementation document as referenced in MOD-001-AB.		
Measure	M1.3. The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or	MR1.1.12 Evidence such as statements in an engineering report exists and shows that requirement R1.1.9 is modeled accurately.		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	Transmission system occurred. (R1.1.2 through R1.1.10) M2. Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).			
Requirement	R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner	R1.2 Uses facility ratings as provided by TFOs, GFOs and interconnected transmission operators.		
Measure	M1.4. The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)	MR1.2 Evidence such as statements in an engineering report exists and shows that ratings in requirement R1.2 are modeled accurately.		
Requirement	R2. The Transmission Operator shall use the following process to determine TTC: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]	R2. The ISO must use the following process to determine total transfer capability:		
Measure	M4. Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it	MR2 Evidence such as statements in an engineering report exists and shows that all sub-requirements of R2 are modeled accurately.		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	determined TTC for the period examined. (R2)			
Requirement	R2.1. Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:	R2.1 Except where otherwise specified within this reliability standard, adjust base case generation and load levels within the updated power flow model to determine the total transfer capability maximum flow or reliability limit that can be simulated on the available transfer capability path while at the same time satisfying all planning criteria contingencies as follows:		
Measure		MR2.1 Evidence exists in the engineering study report.		
Requirement	R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.	R2.1.1 When modeling normal conditions, all transmission elements must be modeled at or below 100% of their continuous rating.		
Measure		MR2.1.1 Evidence exists and shows that the results from the model are within tolerances as specified in requirement R2.1.1.		
Requirement	R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.	R2.1.2 When applying contingencies to the model, the system must demonstrate transient, dynamic and voltage stability, with no transmission element modeled above its emergency rating.		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
Measure		MR2.1.2 Evidence such as statements or results from an engineering report exists and shows that requirement R2.1.2 has been met.		
Requirement	R2.1.3. Uncontrolled separation shall not occur.	R2.1.3 Uncontrolled separation must not occur.		
Measure		MR2.1.3 Evidence such as statements or results from an engineering report exists and shows that requirement R2.1.3 has been met.		
Requirement	R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.	R2.2 Where it is impossible to simulate a reliability-limited flow in a direction counter to prevailing flows on an alternating current transmission line, set the total transfer capability for the non-prevailing direction equal to the total transfer capability in the prevailing direction. If the total transfer capability in the prevailing flow direction is dependant on a remedial action scheme, set the total transfer capability for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum total transfer capability that can be achieved in the prevailing flow direction without use of a remedial action scheme.		
Measure		MR2.2 Evidence such as engineering study reports exists and shows that the		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
		conditions are modeled as specified in requirement R2.2 where conditions apply.		
Requirement	R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.	R2.3 For an available transfer capability path whose capacity is limited by contract to which ISO is a counterparty, set total transfer capability on the available transfer capability path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by requirement R2.1.		
Measure		MR2.3 Evidence such as an engineering study report exists and shows that requirement R2.3 has been met where the condition applies.		
Requirement	R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.	R2.4 For an available transfer capability path, whose total transfer capability varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting total transfer capability under specified conditions.		
Measure		MR2.4 Evidence such as an engineering study report exists and shows that requirement R2.4 has been met where the condition applies.		
Requirement	R2.5. The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing	R2.5 The ISO must identify when the total transfer capability for the available transfer capability path being studied has an adverse impact on the total transfer capability of any existing path.		

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.	This must be done by modeling the flow on the path being studied at its proposed new total transfer capability level, simultaneous with the flow on the existing path at its total transfer capability level, while complying with the reliability criteria outlined in requirement R2.1. The ISO must include the result in its study report for the available transfer capability path.		
Measure		MR2.5 Evidence such as an engineering study report exists and shows that requirement R2.5 has been met where the condition applies.		
Requirement	R2.6. Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.	R2.6 Where multiple ownership of transmission rights exists on an available transfer capability path, total transfer capability of that path must be allocated in accordance with the contracts made by the multiple owners.		
Measure		MR2.6 Evidence such as an engineering study report exists and shows that requirement R2.6 has been met where the condition applies.		
Requirement	R2.7. For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1,	R2.7 For available transfer capability paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has		

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	1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.	been taken to have the path rated using a different method, set the total transfer capability at the established amount.		
Measure	M3. Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)	MR2.7 Evidence such as an engineering study report exists and shows that requirement R2.7 has been met where the condition applies.		
Requirement	R2.8. Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.	R2.8 Create a study report that describes the steps that were undertaken in requirements R2.1 through to R2.7, inclusive, when determining the total transfer capability and the results of the study, including the contingencies and assumptions used. Where three phase fault damping is used to determine stability limits, the study report must also identify the percent used and include justification for use unless specified otherwise in the ATCID, as referenced in MOD-001-AB.		
Measure		MR2.8 Study report exists and documents the evidence showing that requirement R2.1 through to R2.7 is complete and modeled accurately.		
Requirement	R3. Each Transmission	R3 The ISO must establish the total		

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	Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]	transfer capability at the lesser of the available transfer capability calculated in requirement R2 or any system operating limit for that available transfer capability path.		
Measure	M5. Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)	MR3 Evidence such as an engineering study report exists and shows that the total transfer capability value set meets the requirements as specified in requirement R3.		
Requirement	R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.	R4 Within seven calendar days of the finalization of the study report, the ISO must make available within the ISO, as appropriate, the current total transfer capability and the total transfer capability study report documenting the assumptions used and steps taken in determining the current total transfer capability for that available transfer capability path.		

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	[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]			
Measure	M6. Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)	MR4 Evidence exists and shows that the information specified in requirement R4 was communicated in the timeline specified.		
Requirement	<p>R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</p> $TC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$ <p>Where: NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included</p>		Alberta Variance²⁵: The ISO uses an injection/withdrawal based tariff and not a rights or “commitments” based tariff as described in NERC requirement R5 and as such, this requirement has been assessed as not applicable in Alberta.	

²⁵ An Alberta variance is a change from the US reliability standard that the AESO has determined to be material.

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Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	<p>in Transmission Reliability Margin or Capacity Benefit Margin.</p> <p>NITS_F is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.</p> <p>GF_F is the firm capacity set aside for grandfathered 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."</p> <p>PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.</p> <p>ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's</p>			

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Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference ²³	Comments ²⁴
	<p>Transmission Service contract expires or is eligible for renewal. OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.</p>			
Measure	<p>M7. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1 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</p>			

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	R5 to calculate its firm ETC. (R5)			
Requirement	<p>R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</p> $ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$ <p>Where: NITS_{NF} is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin. GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service</p>		<p>Alberta Variance²⁶: The ISO uses an injection/withdrawal based tariff and not a rights or “commitments” based tariff as described in NERC requirement R6 and as such, this requirement has been assessed as not applicable in Alberta.</p>	

²⁶ An Alberta variance is a change from the US reliability standard that the AESO has determined to be material.

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference ²³	Comments ²⁴
	<p>Provider's Open Access Transmission Tariff or "safe harbor tariff." PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service. 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 as specified in the ATCID.</p>			
Measure	<p>M8. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 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</p>			

Assessment and Conversion of NERC MOD-029-1 to Alberta MOD-029-AB-1 Rated System Path Methodology				
Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)			
Requirement	<p>R7. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</p> $ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$ <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 commitments for the ATC Path during that period.</p>	<p>R5 When calculating available transfer capability for an available transfer capability path for a specified period, the ISO must use the following algorithm: $ATC = TTC - TRM$</p> <p>Where ATC_F is the firm available transfer capability for the available transfer capability path for that period.</p> <p>TTC is the total transfer capability of the available transfer capability path for that period.</p> <p>CBM is the capacity benefit margin for the available transfer capability path during that period.</p> <p>TRM is the transmission reliability margin for the available transfer capability path during that period.</p>	<p>Alberta Variance²⁷: NERC requirement R7 identifies the calculation for firm available transfer capability, however, the ISO does not provide rights to its transmission under the Alberta tariff. The calculation provided in the proposed Alberta requirement is for the calculation of available transfer capability. There are no firm commitments for the available transfer capability path, consequently ETC_F, counterflows_F and Postbacks_F are not included in the available transfer capability calculation.</p>	

²⁷ An Alberta variance is a change from the US reliability standard that the AESO has determined to be material.

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Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference ²³	Comments ²⁴
	<p>CBM is the Capacity Benefit Margin for the ATC Path during that period.</p> <p>TRM is the Transmission Reliability Margin for the ATC Path during that period.</p> <p>Postbacks_F are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.</p> <p>counterflows_F are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.</p>	<p>counterflows are adjustments to available transfer capability as determined by the ISO and specified in its available transfer capability implementation document.</p>	<p>AB Variance²⁸: CBM is not used in Alberta.</p>	
Measure	<p>M9. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the</p>	<p>MR5 Accuracy of the calculation is replicated and confirmed, as specified in requirement R5.</p>		

²⁸ An Alberta variance is a change from the US reliability standard that the AESO has determined to be material.

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Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference²³	Comments²⁴
	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. (R7)			
Requirement	<p>R8. When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]</p> $ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$ <p>Where: ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period. TTC is the Total Transfer Capability of the ATC Path for that period.</p>		<p>Alberta Variance²⁹: NERC requirement R8 identifies the calculation for non-firm available transfer capability, however, the ISO does not provide rights to its transmission under the Alberta tariff. The calculation provided in the proposed Alberta requirement R5 is the only calculation used for an available transfer capability path in Alberta.</p>	

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Section	NERC MOD-029-1	Alberta MOD-029-AB-1	Reason for Difference ²³	Comments ²⁴
	<p>ETC_F is the sum of existing firm commitments for the ATC Path during that period.</p> <p>ETC_{NF} is the sum of existing non-firm 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 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 Available Transfer 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 Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.</p>			
Measure	M10. Each Transmission Service Provider shall produce			

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	<p>the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 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. (R8)</p>			
Compliance	<p>To view the compliance section D of the NERC reliability standard follow this link: http://www.nerc.com/files/MOD-029-1.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</p>	

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			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)

- available transfer capability
- balancing authority area
- capacity benefit margin
- Commission
- contingencies
- day
- element
- facilities
- facility ratings
- firm
- generating facility owner (GFO)
- interconnected transmission operators
- interconnection
- ISO
- load
- reliability
- reliability standard
- remedial action scheme
- system
- system operating limit
- transmission facility owner (TFO)
- transmission operators
- transmission reliability margin
- transmission service providers
- total transfer capability

Standard Owner:

Jerry Mossing, Director, Operations Planning

AESO Requirement Owner(s):

Steve Heidt, Manager, Operations Planning and Analysis - for requirements R1 to R4.

AESO Subject Matter Expert(s):

Steve Heidt, Manager, Operations Planning and Analysis
 Neil Curtis, Director, Grid and Market Operations is the SME for NERC requirements R5 to R9

Work Group Comments:

No outstanding comments or concerns.

Work Group Response:

None required.

Work Group Recommendation:

The OWG members support the recommendation to submit this reliability standard to the ARC.

Developed by:

Name	Organization	Role
Jerry Mossing	AESO	OWG chair
Steve Heidt	AESO	Subject Matter Expert
Doug Hincks	AESO	OWG alternate chair (preliminary review)
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AESO Reliability Committee (ARC) Agenda - Continued

Rick Spyker	AltaLink	OWG – Team member (preliminary review)
Kevin Neithercut	ENMAX	OWG – Team member (preliminary review)
Mark Thompson	AESO	OWG – Team member (preliminary review)
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Peter Wong	AESO	Compliance Measures
Elizabeth Olivier	Consultant	Technical writer review
Larry Kram	AESO	Legal review
Blaise Smith	TransAlta	OWG member
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Travis Robinson	EPCOR	OWG member
Peter Bartsch	AltaLink	OWG member
Roy Hanson	ENMAX Generation	OWG member
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