

## Comments/Questions

For comments or questions about the reliability standards or

To submit comments on NERC or WECC reliability standards for AESO consideration contact:

### Mark Thompson

External Reliability Standards Coordinator

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## Related Links

- [NERC Standards Development](#)
- [WECC Standards Development](#)
- [AESO Reliability Standards Monthly Reports](#)
- [AESO Reliability Committee](#)
- [Alberta Reliability Standards](#)

## In This Issue

The Reliability Standards Monthly Report provides an overview of the AESO's activities related to NERC and WECC standards, business practices and criterion that are posted for review, comment or balloting.

The AESO consults with internal subject matter experts, members of the [AESO Reliability Committee \(ARC\)](#) working groups and the Standards Review Committee (SRC) of the ISO/RTO Council (IRC) when responding to NERC and WECC on the standards.

The report also includes a summary of ARC and its work group activities associated with reliability standards.

## NERC Standards

Standard	Name/Description	Status	Due Date
<a href="#">COM-001-2</a> <a href="#">COM-002-3</a> <a href="#">IRO-001-2</a> <a href="#">IRO-014-2</a>	Reliability Coordination	Comment Period Ended	2010-02-18
<a href="#">MOD-024-2</a>	Generator Verification	Comment Period Ended	2010-02-18
<a href="#">COM-001-1.1</a>	Real-Time Tools	Comment Period Ended	2010-02-18
<a href="#">PRC-010-0</a> <a href="#">PRC-022-1</a>	Assessment of the Design and Effectiveness of UVLS Program and Under-Voltage Load Shedding Program Performance	Comment Period Ended	2010-02-19
<a href="#">TOP-002-2a R10</a>	Normal Operations Planning	Ballot period Ended	2010-02-22
<a href="#">EOP-001-1</a> <a href="#">EOP-001-2</a>	Emergency Operations Planning	Ballot period Ended	2010-02-22
<a href="#">TOP-002-2a R6</a>	Normal Operations Planning	Ballot period Ended	2010-02-22
<a href="#">BAL-002-0</a>	Disturbance Control Performance	Ballot period Ended	2010-02-26



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## NERC Standards

Standard	Name/Description	Status	Due Date
<a href="#">PRC-001-1</a>	System Protection Coordination	Ballot period Ended	2010-02-26
<a href="#">BAL-003-0</a>	Frequency Response and Bias	Ballot period Ended	2010-02-26
<a href="#">TPL-001-1</a>	Transmission System Planning Performance Requirements	Ballot Period Ended	2010-03-01
<a href="#">TOP-001-1</a>	Reliability Responsibilities and Authorities	Pre-Ballot Review	2010-03-01
<a href="#">EOP-003-1</a>	Load Shedding Plans	Ballot Period	2010-03-08
<a href="#">EOP-008-1</a>	Backup Facilities	Comment Period	2010-03-08
<a href="#">Multiple Standards</a>	Transmission Requirements at the Generation Interface	Comment Period	2010-03-15
<a href="#">VAR-001-1a</a> <a href="#">VAR-002-1</a>	Voltage and Reactive Control & Generator Operation for Maintaining Network Voltage Schedules	Comment Period	2010-03-26
<a href="#">CIP-004-2</a>	Cyber Security — Personnel & Training	Pre-Ballot Review	2010-03-29



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## WECC Standards and Related Postings

Standard or Criterion	Name/Description	Status	Due Date
<a href="#">WECC-0056</a> <a href="#">INT-BPS-007-1</a>	Real Time Processing of Late Electronic Tags	Comment Period	2010-03-01
<a href="#">WECC-0058</a> <a href="#">Definition</a>	Bulk Electric System	Comment Period Ended	2010-03-17
<a href="#">WECC-0053</a> <a href="#">INT-BPS-001-3</a>	Tagging Regional Criteria	Comment Period	2010-03-22
<a href="#">WECC-0054</a>	WECC Interchange Authority Backup	Comment Period	2010-03-29

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## Alberta Reliability Standards Under Development

Standard	Name/Description	Status	Due Date
EOP-001-AB-1	Emergency Operations Planning	Stakeholder Consultation Ended	2009-11-05
BAL-004-1 N/A	Time Error Correction	ARC Approval pending	TBD
BAL-004-WECC-AB-1	Automatic Time Error Correction	ARC Approval pending	TBD
EOP-005-AB-2	System Restoration from Blackstart Resources	Stakeholder Consultation	2010-03-18
EOP-008-AB-0	Plans for Loss of Control Center Functionality	Stakeholder Consultation Pending	Q2
IRO-001-AB-1	Reliability Coordination Responsibilities and Authorities	Stakeholder Consultation Pending	Q2
MOD-008-0 N/A	Transmission Reliability Margin	ARC Approval pending	Q2
PRC-005-AB-1	Transmission and Generation Protection System Maintenance and Testing	Stakeholder Consultation Pending	Q2
PRC-011-AB-0	System Maintenance and Testing	ARC Approval Pending	Q2
PRC-015-AB-0	Special Protection System Data and Documentation	Stakeholder Consultation Pending	Q2

N/A means Not Applicable in Alberta

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## Alberta Reliability Standards Under Development

Standard	Name/Description	Status	Due Date
PRC-016-AB-0	Special Protection System Misoperations	Stakeholder Consultation Pending	Q2
PRC-017-AB-0	Special Protection System Maintenance and Testing	ARC Approval Pending	Q2
PRC-018-AB-1	Disturbance Monitoring Equipment Installation and Data Reporting	Stakeholder Consultation Pending	Q2
PRC-023-AB-1	Transmission Relay Loadability	Stakeholder Consultation Pending	Q2
VAR-001-AB-1a	Voltage and Reactive Control	Stakeholder Consultation Pending	Q2
VAR-002-AB-1.1b	Generator Operation for Maintaining Network Voltages	Stakeholder Consultation Pending	Q2
VAR-002-WECC-AB-1	Automatic Voltage Regulators	Stakeholder Consultation Pending	Q2
VAR-501-WECC-AB-1	Power System Stabilizer	Stakeholder Consultation Pending	Q2
BAL-002-AB-0	Disturbance Control Performance	Internal Review	Ongoing
BAL-002-WECC-AB-1	Contingency Reserves	Internal Review	Ongoing
MOD-001-AB-1	Available Transmission System Capability	Internal Review	Ongoing

N/A means Not Applicable in Alberta

## Alberta Reliability Standards Under Development

Standard	Name/ Description	Status	Due Date
MOD-010-AB-0	Steady-State Data for Transmission System Modeling and Simulation	Internal Review	Ongoing
MOD-011-0 N/A	Regional Steady-State Data Requirements and Reporting Procedures	ARC Approval to Reject	Pending
MOD-012-AB-0	Dynamics Data for Transmission System Modeling and Simulation	Internal Review	Ongoing
MOD-024-AB-1	Verification of Generator Gross and Net Real Power Capability	Internal Review	Ongoing
MOD-025-AB-1	Verification of Generator Gross and Net Reactive Power Capability	Internal Review	Ongoing
MOD-028-1 N/A	Area Interchange Methodology	ARC Approval to Reject	Pending
MOD-029-AB-1	Area Interchange Methodology	Internal Review	Ongoing
MOD-030-1 N/A	Flowgate Methodology	ARC Approval to Reject	Pending
BAL-005-AB-0.1b	Automatic Generation Control	Work Group Review	2010-02-01
COM-001-AB-1	Telecommunications	Work Group Review	2010-02-01
COM-002-AB-2	Communications and Coordination	Work Group Review	2010-02-01
FAC-010-AB-2	System Operating Limits Methodology for the Planning Horizon	Work Group Review	2010-02-01

N/A means Not Applicable in Alberta

## Alberta Reliability Standards Under Development

Standard	Name/ Description	Status	Due Date
FAC-011-AB-2	System Operating Limits Methodology for the Operations Horizon	Work Group Review	2010-02-01
FAC-012-AB-1	Transfer Capability Methodology	Work Group Review	2010-02-01
FAC-013-AB-1	Establish and Communicate Transfer Capabilities	Work Group Review	2010-02-01
FAC-014-AB-2	Establish and Communicate System Operating Limits	Work Group Review	2010-02-01
IRO-004-AB-2	Reliability Coordination Operations Planning	Work Group Review	2010-02-01
IRO-005-AB-3	Reliability Coordination Current Day Operations	Work Group Review	2010-02-01
IRO-006-AB-4.1	Reliability Coordination Transmission Loading Relief	Work Group Review	2010-02-01
PER-003-0	Operating Personnel Credentials	Work Group Review	2010-02-01
PER-005-1	System Personnel Training	Work Group Review	2010-02-01
PRC-007-0	Assuring Consistency with Regional UFLS Program Requirements	Work Group Review	2010-02-01
PRC-008-0	Underfrequency Load Shedding Equipment Maintenance Programs	Work Group Review	2010-02-01
CIP-002-2	Cyber Security Critical Cyber Asset Identification	Work Group Review	2010-02-22

N/A means Not Applicable in Alberta

## Alberta Reliability Standards Under Development

Standard	Name/ Description	Status	Due Date
CIP-003-2	Cyber Security Management Controls	Work Group Review	2010-02-22
CIP-004-2	Cyber Security Personnel and Training	Work Group Review	2010-02-22
CIP-005-2	Cyber Security Electronic Security Perimeter(s)	Work Group Review	2010-02-22
CIP-006-2	Physical Security of Critical Cyber Assets	Work Group Review	2010-02-22

N/A means Not Applicable in Alberta

## Reliability Committee and Work Group Highlights

**Alberta Reliability Committee (ARC)** – An ARC meeting was held November 16 2009. The ARC reviewed 14 reliability standards that are currently being prepared for submission to the AUC. Peter Wong made a presentation on compliance to address concerns on the role of the audit team and RSAW development. The next ARC meeting is scheduled for March 24, 2010. [More...](#)

**Operations Work Group** – The OWG met on February 1, 2010. The group completed the initial WG review of 16 standards targeted for the Q4 2010 cycle. The next WG meeting will be held on April 19, 2010. [More...](#)

**Technical Work Group** – The TWG met on November 4. The group reviewed the PRC standards scheduled for the May 2010 cycle. Future meetings will be scheduled as required. [More...](#)

**Transmission Planning Work Group** – Four Alberta TPL Standards have been approved by the AUC. [More...](#)

**Security Work Group** – The SWG met on February 22. The group continued review of CIP-002, 003, 004, 005 and began review of 006. CIP-001-AB-1 has been approved by the AUC. The next meeting is scheduled for March 22. [More...](#)

**Compliance Work Group** – The implementation phase work of the CWG is complete. Additional meetings of the CWG will be scheduled as required. [More...](#)

**Standards Review Committee (SRC) of ISO/RTO Council** - The SRC holds biweekly teleconferences and quarterly meetings to discuss and review the current NERC standards posted for review and to draft group responses to them. There was a quarterly meeting hosted by ERCOT on January 26 & 27, 2010.



# AESO Reliability Standards Monthly Report

February 2010

## COM-001-2, COM-002-3, IRO-001-2 & IRO-014-2 - Reliability Coordination

### **Purpose:**

Draft 3 standards, posted for comment.

### **Current Standards:**

Most of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process. There have been suggestions for improving these requirements, and the drafting team will consider comments submitted by stakeholders, drafting teams and FERC in determining what changes should be proposed to stakeholders.

### **Proposed Standards:**

The proposed standards are meant to:

- ensure that the reliability related requirements applicable to the Reliability Coordinator are clear, measurable, unique, and enforceable,
- ensure that this set of requirements is sufficient to maintain reliability of the Bulk Electric System,
- revise the group of standards based on FERC Order 693.

### **Applicability:**

Reliability Coordinator, Balancing Authority, Transmission Service Provider, Transmission Operator, Distribution Provider, Generator Operator, Purchasing Selling Entity and Load Serving Entity

### **Current Status:**

The standards were posted for comment until February 18, 2010. The AESO submitted comments as a member of the SRC, which can be seen using the link below.

### **NERC Link:**

[Reliability Coordination](#)



# AESO Reliability Standards Monthly Report

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## MOD-024-2 – Verification and Data Reporting of Generator Real Power Capability

### Purpose:

Draft 1 of the revised standard, posted for comment.

### Current Standard:

MOD-024-1, Verification of Generator Gross and Net Real Power Capability, was approved by the NERC Board February 7, 2006. It has not been approved for enforcement under Section 215 by FERC because it contains “fill-in-the-blank” characteristics with responsibilities assigned to the Regional Reliability Organization.

### Proposed Standard:

MOD-024-2 is part of NERC Project 2007-09.

New standards to be finalized as part of this project are:

PRC-019 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

PRC-024 — Generator Performance During Frequency and Voltage Excursions

MOD-026 — Verification of Models and Data for Generator Excitation System Functions

MOD-027 — Verification of Generator Unit Frequency Response

Standards to be revised as part of this project are:

MOD-024 — Verification of Generator Gross and Net Real Power Capability

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability

The standards are to ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit’s capabilities).

They will also ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.

All six of the standards included in this project address generator verifications needed to support bulk power system reliability. All six of the standards included in this project were originally “Phase III & IV Planning Measures” that were translated into new or a proposed standards as part of the Version 0 translation effort. Stakeholders have already agreed that there is a reliability-related need for each of these standards as part of the work performed in association with the Phase III & IV Modeling SAR. In addition, each of the standards included in this project has some “fill in the blank” requirements assigned to the Regional Reliability Organization that need to be replaced with more specific “continent-wide” requirements before the standards are approved.

### Applicability:

Generator Owner, Planning Coordinator, Resource Planner and specified facilities

### Current Status:

The standard was posted for comment until February 18, 2010. The AESO submitted comments as a member of the SRC, which can be seen using the link below.

### NERC Link:

[Generator Verification](#)



# AESO Reliability Standards Monthly Report

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## COM-001-1.1 - Real-time Reliability Monitoring and Analysis Capabilities

### **Purpose:**

Draft 2 SAR, posted for comment.

### **Current Standard:**

COM-001-1.1 was approved by the NERC Board of Trustees on October 29, 2008.

### **Proposed Standard:**

The new or revised standard(s) will establish requirements for the functionality, performance, and change management of Real-time capabilities for Reliability Coordinators, Transmission Operators, Generator Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations.

The scope of the SAR is to establish requirements for the monitoring and analysis capabilities provided to System Operators and used to support Real-time System Operations. The SAR addresses availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management. The intent is to describe 'what' needs to be done but not 'how' to do it.

### **Applicability:**

Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator

### **Current Status:**

The SAR was posted for comment until February 18, 2010. The AESO submitted comments as a member of the SRC, which can be seen using the link below.

### **NERC Link:**

[Real-time Reliability](#)



# AESO Reliability Standards Monthly Report

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## PRC-010-0 Assessment of the Design and Effectiveness of UVLS Program PRC-022-1 Under-Voltage Load Shedding Program Performance

### **Purpose:**

Draft 1 SAR, posted for comment.

### **Current Standards:**

PRC-010-0 was approved by the NERC Board of Trustees on February 8, 2005 and PRC-022-1 was approved on February 7, 2006.

### **Proposed Standard:**

The consolidated standard on Under Voltage Load Shedding (UVLS) will include criteria for Under Voltage Load Shedding programs such that the programs work as intended to shed load when needed and prevent voltage collapse and voltage instability in the Bulk Electric System.

### **Applicability:**

Reliability Coordinator, Planning Coordinator, Transmission Planner, Transmission Owner, Transmission Operator, Distribution Provider, Generator Owner, Generator Operator

### **Current Status:**

The SAR was posted for comment until February 19, 2010. The AESO submitted comments as a member of the SRC, which can be seen using the link below.

### **NERC Link:**

[Under Voltage Load Shedding](#)



# AESO Reliability Standards Monthly Report

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## TOP-002-2a - Normal Operations Planning

### **Purpose:**

Florida Municipal Power Pool request for interpretation.

### **Standard:**

The standard was approved by the NERC Board of Trustees on November 1, 2006.

### **Request:**

In Requirement 10, is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

### **NERC Interpretation:**

Yes. As stated in the NERC Glossary of Terms used in Reliability Standards, the Balancing Authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time. The Balancing Authority does not possess the Bulk Electric System information necessary to manage transmission flows. Therefore, the Balancing Authority must communicate with and follow the directions of the Transmission Operator to meet all SOLs and IROLs.

### **Applicability:**

Balancing Authority, Transmission Service Provider, Transmission Operator, Generator Operator, Load Serving Entity

### **Current Status:**

The interpretation was posted for ballot review until February 22, 2010. The AESO voted in favour of the interpretation. The ballot body voted in favour of the interpretation, but there were negative ballots with comments which results in a recirculation ballot.

### **NERC Link:**

[Normal Operations Planning RFI](#)



# AESO Reliability Standards Monthly Report

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## EOP-001-1 and EOP-001-2 - Emergency Operations Planning

### **Purpose:**

Florida Municipal Power Pool request for interpretation.

### **Standard:**

EOP-001-1 was approved by the NERC Board of Trustees on October 17, 2008 and EOP-001-2 was approved August 25, 2009.

### **Request:**

In reference to Requirement 2.2, does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?

### **NERC Interpretation:**

The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and agreements with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001-0."

### **Applicability:**

Balancing Authority, Transmission Operator

### **Current Status:**

The interpretation was posted for ballot review until February 22, 2010. The AESO voted in favour of the interpretation. The ballot body voted in favour of the interpretation, but there were negative ballots with comments which results in a recirculation ballot.

### **NERC Link:**

[Emergency Operations Planning RFI](#)



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## TOP-002-2a - Normal Operations Planning

### **Purpose:**

Florida Municipal Power Pool request for interpretation.

### **Standard:**

The standard was approved by the NERC Board of Trustees on November 1, 2006.

### **Request:**

Is the responsibility of a BA under Requirement 6 to plan to meet CPS and DCS under unscheduled changes in the system configuration and generation dispatch?

### **NERC Interpretation:**

As stated in the NERC Glossary of Terms used in Reliability Standards, the Balancing Authority “integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.” To this end and in accordance with NERC Reliability Standards BAL-001-0.1a and BAL-002-0, Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any system condition. Balancing Authorities are not responsible for the operation of the transmission system. The Transmission Operator is responsible for the real-time operating reliability of the transmission assets under its purview, and as such has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding load, generation, and interchange for transmission concerns both predicted (e.g. through unit commitment) and actual (e.g. through re-dispatch, interchange modifications, or load shedding). If the actions of Balancing Authorities do not resolve the transmission issues, it is the responsibility of the Transmission Operators or Reliability Coordinators to direct alternative actions.

### **Applicability:**

Balancing Authority, Transmission Service Provider, Transmission Operator, Generator Operator, Load Serving Entity

### **Current Status:**

The interpretation was posted for ballot review until February 22, 2010. The AESO voted in favour of the interpretation. The ballot body voted in favour of the interpretation, but there were negative ballots with comments which results in a recirculation ballot.

### **NERC Link:**

[Normal Operations Planning RFI](#)

## BAL-002-0 - Disturbance Control Performance

### **Purpose:**

Northwest Power Pool request for interpretation.

### **Standard:**

The standard was approved by the NERC Board of Trustees on February 8, 2005.

### **Request:**

The questions are in reference to R4, R5 and Section D, 4.1.

Q1: Although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

Q2: With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?

Q3: Clarify the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

### **NERC Interpretation:**

Response 1: The BAL-002-0 Reliability Standard does not grant an exclusion from compliance evaluation for all Disturbances that exceed the most severe single Contingency. The standard excludes from compliance evaluation specific Disturbances. Simultaneous Contingencies that have a combined magnitude in excess of that of the most severe single Contingency are excluded from compliance evaluation. Subsequent contingencies following an initial Reportable Disturbance that occur more than one minute after the start of the Reportable Disturbance but within the Reportable Disturbance Period can be excluded from compliance evaluation; however, the initial Reportable Disturbance is not excluded from compliance evaluation.

Response 2: As discussed in the response to Question 1, the exclusion from compliance evaluation does not apply to all Disturbances with combined magnitudes exceeding the most severe single Contingency.

As described in Requirement R5, the Reserve Sharing Group in its entirety is "considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members." Therefore, the "exclusion from compliance evaluation" would apply, regardless of the



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location of the Contingencies associated with the Reportable Disturbance within the Reserve Sharing Group, only if:

1. All Reportable Disturbances being considered as contributing to the Reserve Sharing Group's Reportable Disturbance condition each had an associated call by the group member with the Reportable Disturbance for the activation of Contingency Reserves from one or more other group members, and
2. The Reserve Sharing Group's Reportable Disturbance was either based on Simultaneous Contingencies with a combined magnitude in excess of the most severe single Contingency, or was a subsequent contingency that occurred more than one minute after the start of a Reportable Disturbance but within the Reportable Disturbance Period.

Response 3: As discussed in the response to Question 1, the exclusion from compliance evaluation does not apply to all Disturbances that exceed the most severe single Contingency.

Measure M1 of BAL-002-0 details the calculation of the percentage recovery for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or Reserve Sharing Group's most severe single contingency loss. In addition to describing the calculation, the measure indicates that there will be a calculation of average percent recovery for Reportable Disturbances during a given quarter and a similar calculation for excludable Disturbances. Since calculation of both metrics is described in Measure M1, the phrase "excluded from compliance evaluation" indicates that the specified disturbances shall not be included in the calculation of "average percent recovery for Reportable Disturbances," but will be included in the "average percent recovery for excludable Disturbances," as specified in Measure M1. As indicated in Section D.1, compliance with the DCS will be measured on a percentage basis using these measures.

While an entity's average percent recovery for Reportable Disturbances may be calculated as 100%, BAL-002-0 Requirement R3 still requires a Balancing Authority or Reserve Sharing Group to "activate sufficient contingency reserves to comply with the DCS." The Compliance Enforcement Authority, when verifying compliance with BAL-002-0, will be taking numerous factors into account, including whether or not the Balancing Authority or Reserve Sharing Group carried at least enough Contingency Reserve to cover the most severe single contingency. However, the determination of whether or not a violation of the standard has occurred rests with the Compliance Enforcement Authority. To the extent explicit limits are desired, they must be clearly specified in the requirements of the standard.

#### **Applicability:**

Balancing Authority, Reserve Sharing Groups, Regional Reliability Organization

#### **Current Status:**

The interpretation was posted for ballot until February 26, 2010. The AESO cast a negative ballot. The interpretation is going to recirculation ballot.

#### **NERC Link:**

[Disturbance Control Performance RFI](#)



# AESO Reliability Standards Monthly Report

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## PRC-001-1 - System Protection Coordination

### **Purpose:**

Wisconsin Public Service Corporation request for interpretation.

### **Standard:**

The standard was approved by the NERC Board of Trustees on November 1, 2007.

### **Request:**

WPSC is requesting clarification of the term "Generator Operator" as it applies to Requirement 1.

### **NERC Interpretation:**

The Generator Operator is one of the functional classes of entities responsible for complying with the standard, and the staff of a Generator Operator could include protection engineers and/or power plant personnel who perform the Generator Operator function. The intent of the requirement is to ensure that the actual personnel performing the Generator Operator function are familiar with the purpose and limitations of the Protection System schemes applied in its area so that the Generator Operator can perform its prescribed responsibilities.

Being "familiar with the purpose and limitations of Protection System schemes applied in its area" does not require an in-depth knowledge of the specific settings and details of each of the applied Protection Systems, but rather a general knowledge of the types and functional characteristics, including capabilities and limitations, of the applied Protection Systems. For example, the applicable entities are expected to have an understanding of how system operations may be affected when a Protection System becomes inoperative.

### **Applicability:**

Balancing Authority, Transmission Operator, Generator Operator

### **Current Status:**

The interpretation was posted for ballot until February 26, 2010. The AESO cast an affirmative ballot. The interpretation is going to recirculation ballot.

### **NERC Link:**

[System Protection Coordination RFI](#)

## BAL-003-0 – Frequency Response and Bias

### **Purpose:**

Request for Interpretation, posted for recirculation ballot.

### **Standard:**

BAL-003-0 was NERC BOT approved on May 13, 2009.

### **Request:**

1. Does NERC BAL-003 require every Balancing Authority to have a Frequency Response close to 1% of its projected peak load?
2. Requirement R2 mandates that each Balancing Authority “establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority’s Frequency Response”. Given the sign convention of the Frequency Bias Setting as applied in the ACE equation, is the Frequency Bias Setting required to be a negative value as close as practical to, or greater than (in absolute terms), the estimated Frequency Response so that AGC will not move resources in a manner that would negate the primary response provided by frequency responsive resources?
3. A) When making the comparison between Frequency Response and Frequency Bias in R2, what is the proper method for this comparison? Should the estimated Frequency Response and Frequency Bias Setting be compared with their typical negative sign convention or in terms of their absolute values? B) In other words, in order to ensure that AGC does not drive resources to negate the primary response to frequency deviation provided by system resources, including governor response, does Requirement R2 require that the absolute value of the Frequency Bias Setting be as close as practical to, or greater than, the absolute value of the estimated Frequency Response per 0.1 Hz change?
4. Is there any defined measure to determine what “as close as practical” means? Requirement R5 mandates that each Balancing Authority that serves native load shall “have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority’s estimated yearly peak demand per 0.1 Hz change. Does Requirement R5 require that the absolute value of the Balancing Authority’s monthly average Frequency Bias Setting be at least 1% of the Balancing Authority’s estimated yearly peak demand per 0.1 Hz change.
5. As the Frequency Bias Setting is typically calculated and applied as a negative value under R2, yet in R5 it is compared against a percentage of a Balancing Authority’s estimated yearly peak demand load and is typically a positive value, is the absolute value of the monthly average Frequency Bias Setting required to be at least 1% of the Balancing Authority’s estimated yearly peak demand per 0.1 Hz change? If not, how does one reconcile the sign convention differences between R2 and R5?
6. Does BAL-003 have any requirements that would set a value on the amount of Frequency Response that a Balancing Authority must provide?

## NERC Interpretation:

1. BAL-003-0.1b does not have a Frequency Response performance obligation.
2. Yes, the Balancing Authority Frequency Bias Setting within the ACE equation is a negative value, expressed in MW/0.1 Hz and should be as close as practical to the natural Frequency Response. If Requirement R2 is met at all times by the Balancing Authority, AGC in Tie Line Bias mode will not move resources in a manner that would withdraw natural Frequency Response.
3. A) Frequency Response and Frequency Bias should be compared with their typical sign convention and not an absolute value. B) Yes, Requirement R2 mandates that the absolute value of Frequency Bias be as close as practical to the absolute value of Frequency Response. Thus, matching Frequency Response and Frequency Bias helps ensure proper AGC performance.
4. There is not a defined measure to determine what "as close as practical" means. Yes, Requirement R5 of the standard, as an alternate method of determining a Balancing Authority's Frequency Bias Setting, uses the Balancing Authority's estimated yearly peak demand, or the Balancing Authority's estimated maximum generation level in the coming year for Balancing Authorities that do not serve native load, as a proxy to determine the Balancing Authority's Frequency Bias obligation per 0.1 Hz change. A 1% value of yearly peak demand per 0.1 Hz or 1% value of estimated maximum generation level in the coming year per 0.1 Hz must be used as the minimum Frequency Bias Setting.
5. Yes, the absolute value of the monthly average Frequency Bias Setting is required to be at least 1% of the Balancing Authority's estimated yearly peak demand or at least 1% of the Balancing Authority's estimated maximum generation level in the coming year for Balancing Authorities that do not serve native load.
6. BAL-003-0.1b does not have any requirements mandating a specific magnitude of Frequency Response by the Balancing Authority.

## Applicability:

Balancing Authorities

## Current Status:

The interpretation was posted for recirculation ballot until February 26, 2010. The AESO voted in favour of the interpretation during the original ballot period and that vote will carry through the recirculation ballot. The interpretation was approved by the ballot body.

## NERC Link:

[Frequency Response and Bias](#)

## TPL-001-1 - Transmission System Planning Performance Requirements

### **Purpose:**

Draft 5, posted for ballot.

### **Current Standards:**

There are currently 6 Version 0 TPL standards dealing with transmission system planning performance requirements: TPL-001-0 through TPL-006-0.

### **Proposed Standard:**

TPL-001-1 is designed to be a single, comprehensive, and coordinated standard that merges the requirements of four existing standards: TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0. The proposed standard includes several new definitions.

The purpose of the proposed standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. The project includes updating and consolidating the following standards:

- TPL-001-0 — System Performance under Normal Conditions
- TPL-002-0 — System Performance Following Loss of a Single BES Element
- TPL-003-0 — System Performance Following Loss of Two or More BES Elements
- TPL-004-0 — System Performance Following Extreme BES Events
- TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
- TPL-006-0 — Data from the Regional Reliability Organization Needed to Assess Reliability

This part of the project addresses TPL-001-0 through TPL-004-0. TPL-005 and TPL-006 will be addressed later in the project.

### **Applicability:**

Transmission Planner, Planning Coordinator

### **Current Status:**

The standard was posted for ballot until March 1, 2010. The AESO cast an affirmative ballot for the standard. The standard is going to recirculation ballot.

### **NERC Link:**

[Assess Transmission and Future Needs](#)



# AESO Reliability Standards Monthly Report

February 2010

## TOP-001-1 – Reliability Responsibilities and Authorities

### **Purpose:**

Florida Municipal Power Pool request for interpretation posted for pre-ballot review.

### **Standard:**

The standard was approved by the NERC Board of Trustees on November 1, 2006.

### **Request:**

For Requirement R8 is the Balancing Authority responsibility to immediately take corrective action to restore Real Power Balance and is the TOP responsibility to immediately take corrective action to restore Reactive Power Balance?

### **NERC Interpretation:**

The answer to both questions is yes. According to the NERC Glossary of Terms Used in Reliability Standards, the Transmission Operator is responsible for the reliability of its "local" transmission system, and operates or directs the operations of the transmission facilities. Similarly, the Balancing Authority is responsible for maintaining load-interchange-generation balance, i.e., real power balance. In the context of this requirement, the Transmission Operator is the functional entity that balances reactive power. Reactive power balancing can be accomplished by issuing instructions to the Balancing Authority or Generator Operators to alter reactive power injection. Based on NERC Reliability Standard BAL-005-1b Requirement R6, the Transmission Operator has no requirement to compute an Area Control Error (ACE) signal or to balance real power. Based on NERC Reliability Standard VAR-001-1 Requirement R8, the Balancing Authority is not required to resolve reactive power balance issues. According to TOP-001-1 Requirement R3, the Balancing Authority is only required to comply with Transmission Operator or Reliability Coordinator instructions to change injections of reactive power.

### **Applicability:**

Balancing Authority, Distribution Provider, Transmission Operator, Generator Operator, Load Serving Entity

### **Current Status:**

The interpretation was posted for pre-ballot review until March 1, 2010.

### **NERC Link:**

[Reliability Responsibilities and Authorities RFI](#)



# AESO Reliability Standards Monthly Report

February 2010

## EOP-003-1 – Load Shedding Plans

**Purpose:**

Florida Municipal Power Pool request for interpretation posted for pre-ballot review.

**Standard:**

The standard was approved by the NERC Board of Trustees on November 1, 2006.

**Request:**

Do R3 and R5 apply only to automatic load shedding or both automatic and manual load shedding?

**NERC Interpretation:**

The drafting team interprets the term “load shedding” to include both automatic and manual load shedding if there is no further specificity provided by the requirement; therefore, Requirements R3 and R5 apply to both automatic and manual load shedding.

**Applicability:**

Balancing Authority, Transmission Operator

**Current Status:**

The interpretation is posted for ballot review until March 8, 2010.

**NERC Link:**

[Load Shedding Plans RFI](#)



# AESO Reliability Standards Monthly Report

February 2010

## EOP-008-1 – Backup Facilities

### **Purpose:**

Revised Standard, Draft 5, posted for ballot.

### **Current Standard:**

The current standard is a Version 0 and was adopted from the voluntary standards.

### **Proposed Standard:**

The revised standard is meant to ensure continued reliable operations of the Bulk Electric System in the event that a control center becomes inoperable. The standard has been modified significantly from the “Version 0” standard to add more specificity to the requirements and to address issues raised by FERC in Order 693. The standard incorporates a number of changes based on input received from the industry during the drafting and comment process.

### **Applicability:**

Reliability Coordinators, Transmission Operators, Balancing Authorities

### **Current Status:**

The standard is posted for comment until March 8, 2009.

### **NERC Link:**

[Backup Facilities](#)



# AESO Reliability Standards Monthly Report

February 2010

## Transmission Requirements at the Generator Interface

### Purpose:

Draft 1 SAR, posted for comment.

### Current Standards:

NERC and FERC believe there is a lack of clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.

### Proposed Standards:

32 NERC Reliability Standards contain language regarding generators or generating facilities for which greater clarity regarding its Generator Interconnection Facilities would ensure no reliability gap exists

12 requirements in FAC-003-1 - Transmission Vegetation Management should have their applicability expanded to include Generator Owners.

2 NERC Reliability Standards should have their applicability expanded to include Generator Operators to address general reliability gaps not attributable to their Generator Interconnection Facilities.

8 new Reliability Standard Requirements should be added to ensure the responsibilities for owning and operating the Generator Interconnection Facility are clear, and to address certain requirements that should apply to all generators regardless of interconnection configuration.

New NERC Glossary definitions are needed for Generator Interconnection Facility and Generator Interconnection Operational Interface, as well as modifications to Vegetation Inspection, Right-of-Way, Generator Owner, Generator Operator, and Transmission Operator.

The affected Standards are:

BAL-005, CIP-002, EOP-001, -003, -004, -008, FAC-001, -003, -008, -009, IRO-005, MOD-010, -012, PER-001, -002, PRC-001, -004, -005, TOP-001, -002, -003, -004, -008, VAR-001, -002

### Applicability:

Transmission Owner, Transmission Operator, Generator Owner, Generator Operator

### Current Status:

The SAR is posted for comment until March 15, 2010.

### NERC Link:

[Generator Interface](#)



# AESO Reliability Standards Monthly Report

February 2010

## **VAR-001-1a - Voltage and Reactive Control VAR-002-1 - Generator Operation for Maintaining Network Voltage Schedules**

### **Purpose:**

Version 2 SAR, posted for comment.

### **Current Standards:**

The current standards have been in effect since 2007.

### **Proposed Standards:**

The existing VAR standards will be modified to address the FERC directives in Order 693, and to reflect the Transmission Issues Subcommittee's "Reactive Support & Control Whitepaper" dated 05/18/2009, which identifies the technical requirements needed to determine the reactive resources required under each system state. The report identifies the criteria and associated rationale required to be documented to determine the split of dynamic reactive supply (such as reactive power provided by generators and other dynamic devices) and static reactive power supply (such as static capacitors and other static devices). The report also identifies what criteria must be documented for distribution of the Interconnection's reactive resource needs among transmission, distribution, and generation facilities. New requirements may be added to the existing VAR standards or may be added to a new VAR standard.

### **Applicability:**

Reliability Coordinator, Planning Coordinator, Resource Planner, Transmission Planner, Transmission Owner, Transmission Operator, Distribution Provider, Generator Owner, Generator Operator, Purchase-Selling Entity, Market Operator, Load-Serving Entity

### **Current Status:**

The SAR is posted for comment until March 26, 2010.

### **NERC Link:**

[VAR-001 & 002 SAR](#)



# AESO Reliability Standards Monthly Report

February 2010

## CIP-004-2 – Cyber Security – Personnel and Training

### **Purpose:**

Request for Interpretation

### **Standard:**

This Version 2 CIP standard was recently approved by FERC.

### **Request:**

The US Army Corps of Engineers asks:

- 1) What sources of verification (as alternatives to Social Security Number verification) are acceptable? Would verification of a Driver's license, passport or birth certificate be acceptable under requirement R3.1?
- 2) Is ID Verification required every seven years as stated in R3.2 for all situations or only in situations where an employee has a break in service or a name change?
- 3) What is meant by the term "seven-year criminal check" in R3.1? Is a local or state check sufficient or is a national database required?

### **NERC Interpretation:**

1) The intent of identity verification is to ensure positive verification of an individual identity and that the risk assessment is performed on the same person who is being granted cyber or unescorted physical access. Each entity shall have a documented personnel risk assessment program that ensures each individual is positively identified.

The drafting team interprets that acceptable alternatives to the Social Security number verification are a current passport, driver's license, or identification (ID) card issued by a state or province or outlying possession of the United States; a Permanent Resident Card or Alien Registration Receipt Card; U.S., Mexican, or Canadian military ID card; or Native American tribal document or Certificate of Indian Status.

2) The drafting team interprets that the personnel risk assessment (identity verification and criminal check) is required every seven years at a minimum. Requirement R3.1 states "The Responsible Entity shall ensure that each assessment conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven year criminal check." Since the wording of Requirement R3.1 does not make a distinction between the first and subsequent personnel risk assessments, the seven-year update requires both the identity verification and the seven-year criminal check.

3) The drafting team acknowledges that the requirement does not define "seven year criminal check." The team interprets that due to the nature of cyber and unescorted physical access to critical facilities, the risk assessment must encompass a broad examination of an individual's record. Therefore, at least a "local agency check" should be performed. A local agency check is defined as a criminal history records check covering all locations where, during the period covered by the (re)investigation, the subject has resided, been employed, and/or attended school for six months or more, including current residence regardless of duration.

### **Applicability:**

Reliability Coordinator, Balancing Authority, Interchange Authority, Transmission Service Provider, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, Load Serving Entity, NERC and Regional Entity



# AESO Reliability Standards Monthly Report

February 2010

**Current Status:**

The revised interpretation is posted for pre-ballot review until March 29, 2010.

**NERC Link:**

[Cyber Security – Personnel and Training](#)



# AESO Reliability Standards Monthly Report

February 2010

## WECC-0056 – INT-BPS-007-1 – Real Time Processing of Late Electronic Tags

### **Purpose:**

Draft 1 of the revised Criterion, posted for comment.

### **Current Criterion:**

The current Business Practice, now known as Criterion, INT-BPS-007-0 has been in effect since April 27, 2007.

### **Proposed Criterion:**

There are many situations where a Load-Serving Entity (LSE) or Balancing Authority is in a ramp and quickly running out of reserves. They can easily forecast that they will be out of reserves within the next 15 minutes, but cannot exercise and use the emergency designation until they actually run out of reserves. By the time they run out of reserves, and start the process of finding energy, getting an e-tag out and starting the flow of energy, there could easily be many minutes of time that passes where there was a shortage of reserves.

With this proposal, by including forecast emergencies in the definition, an LSE can take quick pre-emptive measures to handle the approaching emergency situation and avert any shortages of reserves.

### **Applicability:**

Balancing Authority, Transmission Service Provider, Purchasing-Selling Entity

### **Current Status:**

A questionnaire for comments was posted until March 1, 2010. The AESO submitted comments which can be seen using the link below.

### **WECC Link:**

[Real Time Processing of Late Electronic Tags](#)



# AESO Reliability Standards Monthly Report

February 2010

## WECC-0058 – Bulk Electric System

### **Purpose:**

The Bulk Electric System (BES) Definition Task Force (BESDTF) has posted the fourth draft of their BES proposal for comment.

### **Current Standard:**

Although this is not a Standard, the BESDTF has agreed to follow the process for developing and approving WECC Standards. The WECC does not currently have a definition for the BES and relies on the NERC definition.

### **Proposed Standard:**

The purpose of the BESDTF is to provide clarity as to which power system elements are deemed to be part of the BES. The BESDTF presented 2 options and 2 voltage classifications to define the BES in the original posting. They have considered all the comments received during the first two posting and have developed the current draft for comment.

### **Applicability:**

All WECC entities.

### **Current Status:**

A questionnaire on the BES definition was posted for comment until March 17.

### **WECC Link:**

[Bulk Electric System](#)



# AESO Reliability Standards Monthly Report

February 2010

## WECC-0053 – INT-BPS-001-3 – Tagging Regional Criteria

**Purpose:**

Draft 1 of the revised Criterion, posted for comment.

**Current Criterion:**

The current Business Practice, now known as Criterion, INT-BPS-001-2 has been in effect since April 27, 2007.

**Proposed Criterion:**

The document is meant to identify WECC tagging regional criteria, which are not explicitly addressed in NERC Reliability Standards or NAESB business practice standards, but are considered necessary for all transaction sinking within the Western Interconnection.

**Applicability:**

Balancing Authority, Transmission Service Provider, Purchasing-Selling Entity

**Current Status:**

A questionnaire for comments is posted until March 22, 2010.

**WECC Link:**

[Tagging Regional Criteria](#)



# AESO Reliability Standards Monthly Report

February 2010

## **WECC-0054 - WECC Interchange Authority Backup**

### **Purpose:**

Version 2 Criterion, posted for comment

### **Current Criterion:**

The WECC Interchange Authority function is currently an automated function providing net interchange checkout, source/sink net checkout, inadvertent interchange calculation, and notice of confirmed interchange.

### **Proposed Criterion:**

In the event that this automated function fails, the Applicable Entities that rely upon this technology will be unable to timely complete the delineated tasks in accordance with existing NERC Standards such as those included in the Interchange Scheduling and Coordination (INT) segment of the NERC approved standards. Among other concerns, this inability could result in denied e-Tags which in turn would prevent the dispatch of energy from source to sink thereby threatening reliability. This Criterion is designed to establish a remedial process to be undertaken by the Applicable Entities in the event of such a failure.

### **Applicability:**

Reliability Coordinators, Balancing Authorities, Transmission Service Providers, Purchasing-Selling Entities, Interchange Authority

### **Current Status:**

The criterion is posted for comment until March 29.

### **WECC Link:**

[WECC Interchange Authority Backup](#)