BEFORE THE
NOVA SCOTIA UTILITY AND REVIEW BOARD
OF THE PROVINCE OF NOVA SCOTIA

NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION)

SECOND QUARTER 2014 APPLICATION FOR APPROVAL OF RELIABILITY STANDARDS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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August 15, 2014

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The North American Electric Reliability Corporation ("NERC") hereby submits to the Nova Scotia Utility and Review Board ("NSUARB") an application for approval of the NERC Reliability Standards and an updated NERC Glossary of Terms approved by the United States Federal Energy Regulatory Commission ("FERC" or the "Commission"), submitted for informational purposes. This filing covers the time period from April 1, 2014 through June 30, 2014. NERC requests that, as specified herein, these Reliability Standards and Definitions be made mandatory and enforceable for users, owners, and operators of the bulk-power system within the Province of Nova Scotia.

In support of this request for approval of the proposed Reliability Standards and Definitions, NERC submits the following information: (1) Reliability Standards approved by FERC in the second quarter of 2014 and the associated updated *NERC Glossary of Terms* (*see* **Exhibit A**); (2) an informational summary for each Reliability Standard approved by FERC in the second quarter of 2014, including each Standard's purpose, applicability, and ballot body approval percentages (*see* **Exhibit B**); and (3) an updated list of the currently-effective Reliability Standards as approved by FERC (*see* **Exhibit C**).

I. NOTICES AND COMMUNICATIONS

Notices and communications regarding this Application may be addressed to:

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II. REQUEST FOR APPROVAL OF RELIABILITY STANDARDS

A. Background: NERC Quarterly Filing of Proposed Reliability Standards

On July 20, 2011, NSUARB issued a decision approving the Reliability Standards and NERC Glossary of Terms that NERC submitted to NSUARB on June 30, 2010, and accepted as guidance the Violation Risk Factors ("VRF") and Violation Severity Levels ("VSL") associated with the currently-effective Reliability Standards.[1]

NERC has been certified as the Electric Reliability Organization ("ERO")[2] in the United States under Section 215 of the Federal Power Act.[3] The Reliability Standards

[1] *In the Matter of an Application by North American Electric Reliability Corporation for Approval of its Reliability Standards, and an application by Northeast Power Coordinating Council, Inc. for Approval of its Regional Reliability Criteria*, NSUARB-NERC-R-10 (July 20, 2011) ("NSUARB Decision").

[2] Through enactment of the Energy Policy Act of 2005, the U.S. Congress entrusted FERC with the duties of approving and enforcing rules in the U.S. to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an ERO. On July 20, 2006, FERC certified NERC as the ERO, charged with developing mandatory and enforceable Reliability Standards, which are subject to FERC review and approval.

3 16 U.S.C. § 824o(f) (2006).

contained in **Exhibit A** have been approved as mandatory and enforceable for users, owners, and operators within the United States by FERC.[4] Some or all of NERC's Reliability Standards are now mandatory in the Canadian Provinces of Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Québec, and Saskatchewan.

NERC entered into a Memorandum of Understanding ("MOU") with the NSUARB[5] and a separate MOU with Nova Scotia Power Incorporated ("NSPI"), and the Northeast Power Coordinating Council, Inc. ("NPCC"),[6] which became effective on December 22, 2006 and May 11, 2010, respectively. The May 11, 2010 MOU sets forth the mutual understandings of NERC, NSPI, and NPCC regarding the approval and implementation of NERC Reliability Standards and NPCC Regional Reliability Criteria in Nova Scotia and other related matters.

In addition, the NSUARB Decision approved a "quarterly review" process for considering new and amended NERC standards and criteria.[7] On September 2, 2011, NERC submitted its Second Quarter 2011 application filing to NSUARB, in which NERC committed to file a quarterly application with the NSUARB within sixty days after the end of each quarter for approval of all NERC Reliability Standards and updated Glossary of Terms approved by FERC during that quarter.

The NSUARB Decision also determined that quarterly "applications will not be processed by the Board until [FERC] has approved or remanded the standards in the

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[4] Those standards marked with an asterisk are not yet effective, but have been approved by FERC.

[5] *See* Memorandum of Understanding between Nova Scotia Utility and Review Board and North American Electric Reliability Corporation (signed December 22, 2006).

[6] *See* Memorandum of Understanding between Nova Scotia Power Incorporated and the Northeast Power Coordinating Council, Inc. and the North American Electric Reliability Corporation (signed May 11, 2010).

[7] NSUARB Decision at P 30.

United States."[8] Therefore, NERC is only requesting NSUARB approval for those Reliability Standards approved by FERC.

The NSUARB Decision also concluded that NSUARB approval is not required for VRFs and VSLs associated with proposed Reliability Standards.[9] Thus, NERC does not seek formal approval of VRFs and VSLs associated with the Reliability Standards submitted in this quarterly application. However, because the NSUARB has determined that it will accept the VRFs and VSLs as guidance, NERC is providing a link to the associated FERC-approved VRFs and VSLs for the Reliability Standards for informational purposes.[10]

NERC has not included in this filing the full developmental record for the standards, which consists of the draft standards, comments received, responses to the comments by the drafting teams, and the full voting record, because the record for each standard may consist of several thousand pages. NERC will make the full developmental record available to the NSUARB or other interested parties upon request.

B. Overview of NERC Reliability Standards Development Process

NERC Reliability Standards define the requirements for reliably planning and operating the North American bulk-power system. These standards are developed by industry stakeholders using a balanced, open, fair and inclusive process managed by the NERC Standards Committee. The Standards Committee is facilitated by NERC staff and comprised of representatives from ten electricity stakeholder segments. Stakeholders,

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[8] NSUARB Decision at P 30.

[9] *Id*. at P 33.

[10] NERC's VRF and VSL matrices are available at: http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States. *See* left-hand side of webpage for downloadable documents.

through the balloting process, and the NERC Board of Trustees have approved the standards provided in **Exhibit A**.

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) and Appendix 3A (Standards Processes Manual) of its Rules of Procedure.[11] NERC's Reliability Standards development process has been approved by the American National Standards Institute as being open, inclusive, balanced, and fair. The *NERC Glossary of Terms* used in Reliability Standards – most recently updated July 7, 2014 – lists each term that is defined for use in one or more of NERC's continent-wide or Regional Reliability Standards approved by the NERC Board of Trustees, and is submitted for informational purposes.

C. Description of Proposed Definitions and Reliability Standards, Second Quarter 2014

As explained below, four FERC orders were issued in the second quarter of 2014 approving NERC Reliability Standards and related Glossary terms: (1) a letter order approving Reliability Standards MOD-032-1 and MOD-033-1[12] issued on May 1, 2014; (2) an order approving Reliability Standard EOP-010-1 [13] issued on June 19, 2014; (3) an order approving Reliability Standard PER-005-2[14] and two Definitions issued on June

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11 NERC's Rules of Procedure are available at: http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

12 *North American Electric Reliability Corp.*, Docket No. RD14-5-000 (May 1, 2014) (unpublished letter order).

13 *North American Electric Reliability Corp.*, Order No. 797, 147 FERC ¶ 61,209 (2014).

14 *North American Electric Reliability Corp.*, 147 FERC ¶ 61,226 (2014).

19, 2014; and (4) a letter order approving five Interchange Scheduling and Coordination Reliability Standards[15] and fourteen Definitions issued on June 30, 2014.

Reliability Standard	Effective Date
Emergency Preparedness and Operations (EOP) Standard	
EOP-010-1*	4/1/2015
Interchange Scheduling and Coordination (INT) Standards	
INT-004-3*	10/1/2014[16]
INT-006-4*	10/1/2014
INT-009-2*	10/1/2014
INT-010-2*	10/1/2014
INT-011-1*	10/1/2014
Modeling, Data, and Analysis (MOD) Standards	
MOD-032-1*	7/1/2015[17]
MOD-033-1*	7/1/2017
Personnel Performance, Training, and Qualifications (PER) Standard	
PER-005-2*	7/1/2016

* At the time of this filing, all standards marked with an asterisk are not yet effective, but have been approved by FERC and have a future mandatory effective date.

1. MOD-032-1 and MOD-033-1

On May 1, 2014, FERC approved Reliability Standards MOD-032-1- Data for Power System Modeling and Analysis, and MOD-033-1-Steady-State and Dynamics System Model Validation, the withdrawal of pending Reliability Standards MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1 (collectively, the "Existing MOD B

[15] *North American Electric Reliability Corp.*, Docket No. RD14-4-000 (June 30, 2014) (unpublished letter order).

[16] Requirement R3 will become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

[17] Please see the implementation plan for specific compliance dates and timeframes.

Standards")[18] as well as the retirement of Reliability Standards MOD-010-0 and MOD-012-0. Reliability Standards MOD-032-1 and MOD-033-1 are designed to replace, consolidate and improve upon the "Existing MOD B Standards" in addressing system-level modeling data and validation requirements necessary for developing planning models and the Interconnection-wide cases[19] that are integral to analyzing the reliability of the Bulk-Power System.

Reliability Standard MOD-032-1 creates a framework for collecting modeling data that supports existing practices for developing planning models and Interconnection-wide cases and is also flexible enough to accommodate any changes to those practices that become necessary or preferable over time. Reliability Standard MOD-033-1 requires each Planning Coordinator to implement a documented process to perform model validation within its planning area. In addition, the Reliability Standard will serve the important reliability goal of monitoring and improving the accuracy of the models used in power system studies.

3. <u>EOP-010-1 – Geomagnetic Disturbance Operations</u>

On June 19, 2014, FERC approved Reliability Standard EOP-010-1-Geomagnetic Disturbance Operations. Reliability Standard EOP-010-1 is designed to mitigate the effects of geomagnetic disturbances on the Bulk-Electric System by requiring responsible entities to implement Operating Plans and Operating Procedures or

[18] Of the six Existing MOD B Standards, only MOD-010-0 and MOD-12-0 were approved by FERC in Order No. 693. The other four Existing MOD B Standards were deemed "fill-in-the-blank" standards and were neither approved nor remanded but remain pending. *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416, FERC Stats. & Regs. ¶ 31,242, at PP 1131-1222, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). As such, NERC requested approval from FERC to retire MOD-010-0 and MOD-012-0 and withdraw MOD-011-0, MOD-013-1, MOD-014-0, and MOD-015-0.1.

[19] "Interconnection-wide case" refers to a compilation of model information that represents an entire Interconnection.

Processes. Requirement R1 addresses coordination by reliability coordinators within their areas; Requirement R2 addresses the dissemination of space weather information by reliability coordinators to ensure that entities within a reliability coordinator area have the appropriate information necessary to take action and that the same information is available to all entities; and Requirement R3 requires transmission operators to develop GMD Operating Procedures or Processes.

4. PER-005-2

On June 19, 2014, FERC approved Reliability Standard PER-005-2- Operations Personnel Training, the retirement of currently-effective Reliability Standard PER-005-1-Systems Personnel Training, along with one new definition to the NERC Glossary of Terms. The approved definition of the terms "Operations Support Personnel" and "System Operator" are included in the updated *NERC Glossary of Terms* in **Exhibit A**.

The Personnel Performance, Training, and Qualifications ("PER") group of Reliability Standards is intended to help ensure the safe and reliable operation of the interconnected grid through the retention of suitably trained and qualified personnel in positions that can impact the reliable operation of the Bulk-Power System.

Reliability Standard PER-005-2 is designed to ensure that personnel performing or supporting real-time operations on the Bulk-Power System are trained using a systemic approach, and expands the scope of NERC's currently-effective training Reliability Standard to include certain personnel of transmission owners and generator operators.

5. Interchange and Coordination Reliability Standards

On June 30, 2014, FERC approved the following Reliability Standards:

- INT-004-3 – Dynamic Transfers;
- INT-006-4 – Evaluation of Interchange Transactions;
- INT-009-2 – Implementation of Interchange;
- INT-010-2 – Interchange Initiation and Modification for Reliability; and
- INT-011-1 – Intra-Balancing Authority Transaction Identification.

FERC also approved the retirement of the following five currently-effective Reliability Standards:

- INT-001-3 – Interchange Information;
- INT-003-3 – Interchange Transaction Implementation;
- INT-005-3 – Interchange Authority Distributes Arranged Interchange;
- INT-007-1– Interchange Confirmation; and
- INT-008-3—Interchange Authority Distributes Status.

In addition, FERC approved the following ten revised definitions and four new definitions to be added to the *NERC Glossary of Terms*.

Revised Definitions:

- Adjacent Balancing Authority
- Arranged Interchange
- Confirmed Interchange
- Dynamic Interchange Schedule or Dynamic Schedule
- Intermediate Balancing Authority
- Operational Planning Analysis
- Pseudo-Tie
- Request for Interchange
- Sink Balancing Authority
- Source Balancing Authority

New Definitions:

- Attaining Balancing Authority
- Native Balancing Authority

- Composite Confirmed Interchange
- Reliability Adjustment Arranged Interchange

These approved definitions are included in the updated *NERC Glossary of Terms* in **Exhibit A**. The Interchange Coordinator Reliability Standards improve reliability by making transactions more apparent for reliability assessments and by clarifying which functional entities perform interchange authority tasks.

III. CONCLUSION

NERC respectfully requests that the NSUARB approve the Reliability Standards and Definitions as specified herein.

Respectfully submitted,

/s/ *Stacey Tyrewala*

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Exhibit A (1): Reliability Standards Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

Exhibit A (1): Reliability Standards Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

Reliability Standard	Effective Date
Emergency Preparedness and Operations (EOP) Standard	
EOP-010-1*	4/1/2015
Interchange Scheduling and Coordination (INT) Standards	
INT-004-3*	10/1/2014[1]
INT-006-4*	10/1/2014
INT-009-2*	10/1/2014
INT-010-2*	10/1/2014
INT-011-1*	10/1/2014
Modeling, Data, and Analysis (MOD) Standards	
MOD-032-1*	7/1/2015[2]
MOD-033-1*	7/1/2017
Personnel Performance, Training, and Qualifications (PER) Standard	
PER-005-2*	7/1/2016

* At the time of this filing, all standards marked with an asterisk are not yet effective, but have been approved by FERC and have a future mandatory effective date.

1 Requirement R3 will become effective on the first calendar day two calendar quarters after the NAESB Electric Industry Registry is able to accept Pseudo-Tie registrations. All existing and future Pseudo-Ties are to be registered in the NAESB Electric Industry Registry.

2 Please see the implementation plan for specific compliance dates and timeframes.

Exhibit A (2): PDF Copies of Reliability Standards Being Filed For Approval

A. Introduction

1. **Title: Geomagnetic Disturbance Operations**

2. **Number:** EOP-010-1

3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator

   4.1.2 Transmission Operator with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

5. **Background:**

   Geomagnetic disturbance (GMD) events have the potential to adversely impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Protection System Misoperation, the combination of which may result in voltage collapse and blackout.

6. **Effective Date:**

   The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*

1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.

1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area.

M1. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

R2. Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*

M2. Each Reliability Coordinator shall have evidence such as dated operator logs, voice recordings, transcripts, or electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.

R3. Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

3.1. Steps or tasks to receive space weather information.

3.2. System Operator actions to be initiated based on predetermined conditions.

3.3. The conditions for terminating the Operating Procedure or Operating Process.

M3. Each Transmission Operator shall have a GMD Operating Procedure or Operating Process meeting all the provisions of Requirement R3; evidence such as a review or revision history to indicate that the GMD Operating Procedure or Operating Process has been maintained; and evidence to show that the Operating Procedure or Operating Process was implemented as called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Reliability Coordinator and Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations	Medium	The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2.	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area.
R2	Same-day Operations, Real-time Operations	Medium	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate forecasted and current space weather information to all functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.
R3	Long-term Planning, Operations Planning,	Medium	The Transmission Operator had a GMD Operating Procedure or Operating Process,	The Transmission Operator's GMD Operating Procedure or Operating Process	The Transmission Operator's GMD Operating Procedure or Operating Process	The Transmission Operator did not have a GMD Operating Procedure or Operating

	Same-day Operations, Real-time Operations		but failed to maintain it.	failed to include one of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	failed to include two or more of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	Process OR The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process.

D. Regional Variances

None.

E. Interpretations

None.

F. Guideline and Technical Basis

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

An Operating Plan is implemented by carrying out its stated actions.

Coordination is intended to ensure that Operating Procedures are not in conflict with one another. An Operating Plan is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

Elements of Requirement R1 take place in various time horizons. Development of the GMD Operating Plan occurs in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan occurs in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan occurs in the Operations Planning, Same-Day and Real-Time Time Horizons.

Rationale for R2:

Requirement R2 replaces IRO-005-3.1a, Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Space weather forecast information can be used for situational awareness and safe posturing of the system. Current space weather information can be used for monitoring progress of a GMD event.

The Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

Rationale for R3:

In developing an Operating Procedure or Operating Process, an entity may consider entity-specific factors such as geography, geology, and system topology.

An Operating Procedure or Operating Process is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

Version History

Version	Date	Action	Change Tracking
1	11/07/2013	Adopted by the NERC Board of Trustees	
1	6/19/2014	FERC Order issued approving EOP-010-1	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard EOP-010-1 — Geomagnetic Disturbance Operations

United States

Standard	Requirement	Enforcement Date	Inactive Date
EOP-010-1	All	04/01/2015	

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.
4. **Applicability:**
   - **4.1.** Balancing Authority
   - **4.2.** Purchasing-Selling Entity
5. **Effective Date:**

   First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of Dynamic Transfers.

   - R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
   - R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
   - R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
   - R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
   - The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

B. Requirements and Measures

R1. Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time[1] Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]

M1. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)

R2. The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs**:** [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]

2.1. For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.

2.2. For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.

2.3. The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.

M2. The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)

R3. Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support

[1] Please refer to the timing tables of INT-006-4.

congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at: http://www.nerc.com/files/opman_3_2012.pdf.

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
    - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services	Attaining BA	Native BA

as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale R1:

This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

Rationale R2:

This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
3	June 30, 2014	FERC letter order issued approving INT-004-3	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-004-3 — Dynamic Transfers

United States

Standard	Requirement	Enforcement Date	Inactive Date
INT-004-3	All	10/01/2014	

A. Introduction

1. **Title:** **Evaluation of Interchange Transactions**

2. **Number:** INT-006-4

3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. Transmission Service Provider

5. **Effective Date:**

   First day of the second calendar quarter after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

   The content of INT-006-4 has been revised and expanded in the following manner:

   - R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
   - R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
   - R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
   - R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.

- R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.
- Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

Requirements and Measures

R1. Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

1.1. Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.

1.2. Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.

M1. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)

R2. Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

2.1. Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.

M2. Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

R3. The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

3.1. If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.

M3. Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request and, if applicable, communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)

R4. Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
- It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.

M4. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)

R5. For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

5.1. The Source Balancing Authority,

5.2. Each Intermediate Balancing Authority,

5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,

5.4. Each Transmission Service Provider included in the Arranged Interchange, and

5.5. Each Purchasing Selling Entity included in the Arranged Interchange.

M5. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)

B. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R3, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange. OR The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.
R2	Operations Planning,	Lower	N/A	N/A	N/A	The Transmission Service Provider receiving an on-time

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Same-day Operations, Real-time Operations					Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. OR The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4	Operations Planning, Same-day Operations,	Lower	N/A	N/A	N/A	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-time Operations					an Arranged Interchange to Confirmed Interchange.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.	The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange. OR The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange [1] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[2]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[2]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

[1] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[2] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Attachment 1 – Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and $\leq$1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		$\leq$ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and $\leq$1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		$\leq$ 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 5 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 6 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start

[3] Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

[4] See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

		A	B	C	D
If Arranged Interchange [3] is Submitted	**Time Classification**	**Sink BA Makes Initial Distribution of Arranged Interchange[4]**	**BA and TSP Conduct Reliability Assessments**	**Compilation and Distribution Status[4]**	**BA Prepares Confirmed Interchange for Implementation**
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 7 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 8 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		$\leq$ 9 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
<1 hour and $\geq$ 15 minutes prior to ramp start	On-time		$\leq$ 10 minutes from Arranged Interchange receipt		$\geq$ 3 minutes prior to ramp start
$\geq$ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		$\geq$ 39 minutes prior to ramp start
$\geq$ 4 hours prior to ramp start	On-time		$\leq$ 2 hours from Arranged Interchange receipt		$\geq$ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time $\geq$ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		$\geq$ 1 hour 58 minutes prior to ramp start

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - All reliability entities involved in the Arranged Interchange are valid.
    - Generation source and Load sink are defined.
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
    - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
    - Megawatt profile is defined.
    - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
    - Distribute notification as each entity approves or denies an Arranged Interchange.
    - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
    - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

- Submit a request to modify Interchange

- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
  - Receive distribution of Arranged Interchange
  - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
  - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
  - Submit a request to modify Interchange

- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
  - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
  - How to notify others that it is activating the plan
  - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
  - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
  - Delegation of approval rights and proxy actions, if such approaches will be used.
  - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
  - Personnel plans for short-term and extended periods.
  - Training of personnel in the use of the plan.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing

Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

Rationale for R2:

TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3	July 1, 2010	Approved by FERC	Revised
4	February 6, 2014	Adopted by the NERC Board Of Trustees	Revised
4	June 30, 2014	FERC letter order issued approving INT-006-4	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-006-4 — Evaluation of Interchange Transactions

United States

Standard	Requirement	Enforcement Date	Inactive Date
INT-006-4	All	10/01/2014	

A. Introduction

1. **Title:** **Implementation of Interchange**

2. **Number:** **INT-009-2**

3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.

4. **Applicability:**

   4.1. Balancing Authority.

5. **Effective Date:**

   The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

   The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term "Composite Confirmed Interchange" has been introduced.

   The content of INT-009-2 has been revised and expanded in the following manner:

   - R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
   - R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls.
   - R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

R1. Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

1.1. Identical in magnitude to that of the Adjacent Balancing Authority, and

1.2. Opposite in sign or direction to that of the Adjacent Balancing Authority.

M1. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)

R2. The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

M2. The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). (R2)

R3. Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]

M3. The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process).
R3	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
2	June 30, 2014	FERC letter order issued approving INT-009-2	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-009-2 — Implementation of Interchange

United States

Standard	Requirement	Enforcement Date	Inactive Date
INT-009-2	All	10/01/2014	

A. Introduction

1. **Title:** **Interchange Initiation and Modification for Reliability**

2. **Number:** **INT-010-2**

3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.

4. **Applicability:**

   4.1. Balancing Authority

5. **Effective Date:**

   The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

   - R1 is modified to replace "request for Arranged Interchange" with the correct term "Request for Interchange." A rationale was developed to clarify use of the term "energy sharing agreement" for this requirement.
   - R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

R1. The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M1. The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)

R2. Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed

Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M2. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)

R3. Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

M3. The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

> **If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.**

For Pseudo-Ties:

> **If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.**

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

This requirement was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	February 6, 2014	Board of Trustees Adoption	Revised
2	June 30, 2014	FERC letter order issued approving INT-010-2	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-010-2 — Interchange Initiation and Modification for Reliability

<u>United States</u>

Standard	Requirement	Enforcement Date	Inactive Date
INT-010-2	All	10/01/2014	

A. Introduction

1. **Title:** **Intra-Balancing Authority Transaction Identification**
2. **Number:** INT-011-1
3. **Purpose:** To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Load-Serving Entities

5. **Effective Date:**

   The first day of the first calendar quarter that is six months after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   This standard was created in response to a FERC directive in Order 693, paragraph 817: *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.*

   The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

B. Requirements and Measures

R1. Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations]*

M1. Each Load-Serving Entity subject to R1 shall have evidence, such as dated and time-stamped electronic records, documentation of congestion management procedures, or other similar evidence, that a Request for Interchange was submitted for each Point to

Point Transmission Service intra-Balancing Authority transfer subject to R1 or that each intra-Balancing Authority transfer subject to R1 was accounted for in congestion management procedure(s) via an alternate method. (R1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance with R1 for the most recent three months plus the current month unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	*Operations Planning, Same-day Operations*	*Lower*	N/A	N/A	N/A	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees	New standard developed
1	June 30, 2014	FERC letter order issued approving INT-011-1.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard INT-011-1 — Intra-Balancing Authority Transaction Identification

<u>United States</u>

Standard	Requirement	Enforcement Date	Inactive Date
INT-011-1	All	10/01/2014	

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number:** **MOD-032-1**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:**

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

   MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified

						in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

			steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;

			by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service

			Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO]	6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	purposes. [BA, GO, LSE, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:

a. add requirement identifying who provides and who receives data;
b. identify acceptability;
c. standard format;
d. how to deal with new technologies (user written models if no standard model exists); and
e. shareability.

4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving	See Implementation Plan

		MOD-032-1.	posted on the Reliability Standards web page for details on enforcement dates for Requirements.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard MOD-032-1 — Data for Power System Modeling and Analysis

United States

Standard	Requirement	Enforcement Date	Inactive Date
MOD-032-1	R1.	07/01/2015	
MOD-032-1	R2.	07/01/2016	
MOD-032-1	R3.	07/01/2016	
MOD-032-1	R4.	07/01/2016	

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**
2. **Number: MOD-033-1**
3. **Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Effective Date:**

   MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

B. Requirements and Measures

R1. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation;

1.2. Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic local event, at least once every 24 calendar months (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

R2. Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to Section 3.0 of Appendix 4C of the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months; OR The Planning Coordinator did not perform simulation as	The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months; OR	The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1; OR The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months; OR	The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; OR The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months; OR The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
R2	**Long-term Planning**	**Lower**	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator’s planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of “at least once every 24 calendar months” is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a “month 23” dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event’s occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event’s occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator’s system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator’s system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

In FERC Order No. 693, paragraph 1210, the Commission directed inclusion of "a requirement that the models be validated against actual system responses." Furthermore, the Commission directs in paragraph 1211, "that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.
1	May 1, 2014	FERC Order issued approving MOD-033-1.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard MOD-033-1 — Steady State and Dynamic System Model Validation

United States

Standard	Requirement	Enforcement Date	Inactive Date
MOD-033-1	All	07/01/2017	

A. Introduction

1. **Title:** **Operations Personnel Training**

2. **Number:** PER-005-2

3. **Purpose:** To ensure that personnel performing or supporting Real-time operations on the Bulk Electric System are trained using a systematic approach.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator

   4.1.2 Balancing Authority

   4.1.3 Transmission Operator

   4.1.4 Transmission Owner that has:

   4.1.4.1 Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time.

   4.1.5 Generator Operator that has:

   4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

5. **Effective Date:**

   5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

   Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its System Operators, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall present evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M6.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the compliance enforcement authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to review or update, if necessary, its BES company-specific Real-time reliability-related task list each calendar year. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)
R2	**Long-term Planning**	**Medium**	**None**	The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-	The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)	The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.) OR

				related task list each calendar year. (2.1.1.) OR The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4) OR The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)	OR The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)	The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)
R3	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)

					R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (3.1)	
R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)

R5	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator developed training but failed to use a systematic approach. (R5)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to implement training for its Operations Support Personnel. (R5)
R6	**Long-term Planning**	**Medium**	**None**	The Generator Operator failed to evaluate its training established in Requirement R6 each calendar year. (6.1)	The Generator Operator failed to develop training for its personnel. (R6) OR The Generator Operator developed training but failed to use a systematic approach. (R6)	The Generator Operator failed to implement the training for its personnel identified in Requirement R6. (R6)

Guidelines and Technical Basis

Requirement R1 and R2:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:
The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://energy.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

Reference #3: Recognized Operator Training Topics
See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.
http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf

Reference #4: Definitions of Simulation and Simulators

Georgia Institute of Technology – Modeling & Simulation for Systems Engineering
http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

University of Central Florida – Institute for Simulation & Training
Just what is "simulation" anyway (or, Simulation 101)?
And what about "modeling"?
But what does IST do with simulations?
http://www.ist.ucf.edu/overview.htm

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for System Operator:

The definition of the existing NERC Glossary Term "System Operator" has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term "System Operator" contains another NERC Glossary term "Control Center", which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC) personnel.

The modifications to the definition of "System Operator" do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

Rationale for Operations Support Personnel:

The term Operations Support Personnel is used to identify those support personnel of Reliability Coordinators (RC), Balancing Authorities (BA), or Transmission Operators (TOP) that FERC identified in Order No. 693.

Rationale for TO:

Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *"exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap."* See FERC Order 693 at P 1343 and 1347.

Rationale for GOP:

Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that "*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions,* *particularly in an emergency situation in which instructions may be succinct and require immediate action."* Order No. 742 further clarified that the directive "*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2."* Based on the FERC order, this applicability section clarifies which GOP personnel are subject to the standard.

Rationale for changes to R2:

Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3 and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.

Rationale for R3:

This Requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach.

Rationale for changes to R4:

The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations within 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement R4.1 covers the FERC directive for the creation of an implementation plan for simulation technology.

Rationale for R5:

This is a new requirement applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved.

Rationale for R6:

This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

Version History

Version	Date	Action	Change Tracking
1	2/10/2009	Adopted by the NERC Board of Trustees	
1	11/18/2010	FERC Approved	
1	8/26/2013	Updated VSLs based on June 24, 2013 approval.	
2	2/6/2014	Adopted by the NERC Board of Trustees	
2	6/19/2014	FERC Approved	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PER-005-2 — Operations Personnel Training

United States

Standard	Requirement	Enforcement Date	Inactive Date
PER-005-2	All	07/01/2016	

Exhibit A (3): Updated NERC Glossary of Terms

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Glossary of Terms Used in NERC Reliability Standards

Updated July 7, 2014

Introduction:
This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through July 7, 2014.

This reference is divided into two sections, and each section is organized in alphabetical order. The first section identifies all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the second section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards. (WECC, NPCC and Reliability*First* are the only Regions that have definitions approved by the NERC Board of Trustees. If other Regions develop definitions for approved Regional Standards using a NERC-approved standards development process, those definitions will be added to the Regional Definitions section of this glossary.)

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC approved" date added following a final Order approving the definition.

Immediately under each term is a link to the archive for the development of that term.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Any comments regarding this glossary should be reported to the following:
sarcomm@nerc.com with "Glossary Comment" in the subject line.

Continent-wide Definitions:

Regional Definitions:

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Adequacy [Archive]		2/8/2005	3/16/2007	The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adjacent Balancing Authority [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact [Archive]		2/7/2006	3/16/2007	The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Adverse Reliability Impact [Archive]		8/4/2011		The impact of an event that results in Bulk Electric System instability or Cascading.
After the Fact [Archive]	ATF	10/29/2008	12/17/2009	A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement [Archive]		2/8/2005	3/16/2007	A contract or arrangement, either written or verbal and sometimes enforceable by law.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Alternative Interpersonal Communication [Archive]		11/7/2012		Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.
Altitude Correction Factor [Archive]		2/7/2006	3/16/2007	A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service [Archive]		2/8/2005	3/16/2007	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter [Archive]		2/8/2005	3/16/2007	An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error [Archive]	ACE	2/8/2005	3/16/2007 (Becomes inactive 3/31/14)	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Area Control Error [Archive]	ACE	12/19/2012	10/16/2013 (Becomes effective 4/1/2014)	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.
Area Interchange Methodology [Archive]		08/22/2008	11/24/2009	The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has received the Interchange information (initial or revised).
Arranged Interchange [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The state where a Request for Interchange (initial or revised) has been submitted for approval.
Attaining Balancing Authority [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Automatic Generation Control [Archive]	AGC	2/8/2005	3/16/2007	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Flowgate Capability [Archive]	AFC	08/22/2008	11/24/2009	A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability [Archive]	ATC	2/8/2005	3/16/2007	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Available Transfer Capability [Archive]	ATC	08/22/2008	11/24/2009	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Available Transfer Capability Implementation Document [Archive]	ATCID	08/22/2008	11/24/2009	A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
ATC Path [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path[1].

[1] See 18 CFR 37.6(b)(1)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Authority [Archive]	BA	2/8/2005	3/16/2007	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Base Load [Archive]		2/8/2005	3/16/2007	The minimum amount of electric power delivered or required over a given period at a constant rate.
BES Cyber Asset [Archive]		11/26/12	11/22/2013 (Becomes effective 4/1/16)	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. (A Cyber Asset is not a BES Cyber Asset if, for 30 consecutive calendar days or less, it is directly connected to a network within an ESP, a Cyber Asset within an ESP, or to a BES Cyber Asset, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
BES Cyber System [Archive]		11/26/12	11/22/13 (Becomes effective 4/1/16)	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.
BES Cyber System Information [Archive]		11/26/12	11/22/13 (Becomes effective 4/1/16)	Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Blackstart Capability Plan [Archive]		2/8/2005 Will be retired when EOP-005-2 becomes enforceable on (7/1/13)	3/16/2007	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Blackstart Resource [Archive]		8/5/2009	3/17/11	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Block Dispatch [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System [Archive]	BES	2/8/2005	3/16/2007 (Becomes inactive on 6/30/2014)	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System[2] [Archive]	BES	01/18/2012	6/14/13 (Replaced by BES definition FERC approved 3/20/14)	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. **Inclusions:** • **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3. • **I2** - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. • **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan. • **I4** - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

[2] FERC issued an order on April 18, 2013 approving the revised definition with an effective date of July 1, 2013. On June 14, 2013, FERC granted NERC's request to extend the effective date of the revised definition of the Bulk Electric System to July 1, 2014.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			**I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1. **Exclusions:** • **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			• **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. • **E3** - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating); b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • **E4** – Reactive Power devices owned and operated by the retail customer solely for its own use. Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System [Archive]	BES	11/21/2013	3/20/14 (Becomes effective 7/1/2014) (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. **Inclusions:** • **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3. • **I2** – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA. Or, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. • **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan. • **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. • **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4. **Exclusions:** • **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion. Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion. • **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. • **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following: a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System **(Continued)**	BES			generation greater than 75 MVA (gross nameplate rating); b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • **E4** – Reactive Power devices installed for the sole benefit of a retail customer(s). Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.
Bulk-Power System [Archive]		5/9/2013	7/9/2013	A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Burden [Archive]		2/8/2005	3/16/2007	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices [Archive]		8/22/2008	Not approved; Modification directed 11/24/09	Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Bus-tie Breaker [Archive]		8/4/2011	10/17/2013 (Becomes effective 1/1/15)	A circuit breaker that is positioned to connect two individual substation bus configurations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Capacity Benefit Margin [Archive]	CBM	2/8/2005	3/16/2007	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document [Archive]	CBMID	11/13/2008	11/24/2009	A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency [Archive]		2/8/2005	3/16/2007	A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading [Archive]		2/8/2005	3/16/2007	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cascading Outages [Archive]		11/1/2006 Withdrawn 2/12/2008	FERC Remanded 12/27/2007	~~The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.~~
CIP Exceptional Circumstance [Archive]		11/26/12	11/22/13 (Becomes effective 4/1/16)	A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.
CIP Senior Manager [Archive]		11/26/12	11/22/13 (Becomes effective 4/1/16)	A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards, CIP-002 through CIP-011.
Clock Hour [Archive]		2/8/2005	3/16/2007	The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration [Archive]		2/8/2005	3/16/2007	Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor [Archive]		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Composite Confirmed Interchange [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
Confirmed Interchange [Archive]		5/2/2006	3/16/2007	The state where the Interchange Authority has verified the Arranged Interchange.
Confirmed Interchange [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The state where no party has denied and all required parties have approved the Arranged Interchange.
Congestion Management Report [Archive]		2/8/2005	3/16/2007	A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss [Archive]		8/4/2011	10/17/2013 (Becomes effective 1/1/15)	All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Constrained Facility [Archive]		2/8/2005	3/16/2007	A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency [Archive]		2/8/2005	3/16/2007	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Contingency Reserve [Archive]		2/8/2005	3/16/2007	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Contract Path [Archive]		2/8/2005	3/16/2007	An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Center [Archive]		11/26/12	11/22/13 (Becomes effective 4/1/16)	One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
Control Performance Standard [Archive]	CPS	2/8/2005	3/16/2007	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan [Archive]		2/7/2006	3/16/2007	A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path [Archive]		5/2/2006	3/16/2007	A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Critical Assets [Archive]		5/2/2006	1/18/2008 (Becomes inactive 3/31/16)	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets [Archive]		5/2/2006	1/18/2008 (Becomes inactive 3/31/16)	Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment [Archive]		2/8/2005	3/16/2007	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold [Archive]		2/8/2005	3/16/2007	The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets [Archive]		5/2/2006	1/18/2008 (Becomes inactive 3/31/16)	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Assets [Archive]		11/26/12	11/22/2013 (Becomes effective 4/1/16)	Programmable electronic devices, including the hardware, software, and data in those devices.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Cyber Security Incident [Archive]		5/2/2006	1/18/2008 (Becomes inactive 3/31/16)	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Cyber Security Incident [Archive]		11/26/12	11/22/2013 (Becomes effective 4/1/16)	A malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Delayed Fault Clearing [Archive]		11/1/2006	12/27/2007	Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand [Archive]		2/8/2005	3/16/2007	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management [Archive]	DSM	2/8/2005	3/16/2007	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Demand-Side Management [Archive]	DSM	5/6/2014		All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.
Dial-up Connectivity [Archive]		11/26/12	11/22/2013 (Becomes effective 4/1/16)	A data communication link that is established when the communication equipment dials a phone number and negotiates a connection with the equipment on the other end of the link.
Direct Control Load Management [Archive]	DCLM	2/8/2005	3/16/2007	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Dispatch Order [Archive]		08/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations [Archive]		2/8/2005	3/16/2007	Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor [Archive]	DF	2/8/2005	3/16/2007	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider [Archive]	DP	2/8/2005	3/16/2007	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Disturbance [Archive]		2/8/2005	3/16/2007	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard [Archive]	DCS	2/8/2005	3/16/2007	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Disturbance Monitoring Equipment [Archive]	DME	8/2/2006	3/16/2007	Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders[3]: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions
Dynamic Interchange Schedule or Dynamic Schedule [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Dynamic Interchange Schedule or Dynamic Schedule [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A time-varying energy transfer that is updated in Real-time and included in the Scheduled Net Interchange (NIS) term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).

[3] Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Dynamic Transfer [Archive]		2/8/2005	3/16/2007	The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Economic Dispatch [Archive]		2/8/2005	3/16/2007	The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electronic Access Control or Monitoring Systems [Archive]	EACMS	11/26/12	11/22/2013 (Becomes effective 4/1/16)	Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.
Electronic Access Point [Archive]	EAP	11/26/12	11/22/2013 (Becomes effective 4/1/16)	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
Electrical Energy [Archive]		2/8/2005	3/16/2007	The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter [Archive]	ESP	5/2/2006	1/18/2008 (Becomes inactive 3/31/16)	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Electronic Security Perimeter [Archive]	ESP	11/26/12	11/22/2013 (Becomes effective 4/1/16)	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Element [Archive]		2/8/2005	3/16/2007	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Emergency or BES Emergency [Archive]		2/8/2005	3/16/2007	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange [Archive]	Emergency RFI	10/29/2008	12/17/2009	Request for Interchange to be initiated for Emergency or Energy Emergency conditions.
Energy Emergency [Archive]		2/8/2005	3/16/2007	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Equipment Rating [Archive]		2/7/2006	3/16/2007	The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
External Routable Connectivity [Archive]		11/26/12	11/22/2013 (Becomes effective 4/1/16)	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.
Existing Transmission Commitments [Archive]	ETC	08/22/2008	11/24/2009	Committed uses of a Transmission Service Provider’s Transmission system considered when determining ATC or AFC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Facility [Archive]		2/7/2006	3/16/2007	A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating [Archive]		2/8/2005	3/16/2007	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault [Archive]		2/8/2005	3/16/2007	An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk [Archive]		2/7/2006	3/16/2007	The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand [Archive]		2/8/2005	3/16/2007	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service [Archive]		2/8/2005	3/16/2007	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover [Archive]		2/7/2006	3/16/2007	An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate [Archive]		2/8/2005	3/16/2007	A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Flowgate [Archive]		08/22/2008	11/24/2009	1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology [Archive]		08/22/2008	11/24/2009	The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage [Archive]		2/8/2005	3/16/2007	1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias [Archive]		2/8/2005	3/16/2007	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Bias Setting [Archive]		2/8/2005	3/16/2007 (Becomes inactive 3/31/15)	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Bias Setting [Archive]		2/7/2013	1/16/2014 (Becomes effective 4/1/15)	A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.
Frequency Deviation [Archive]		2/8/2005	3/16/2007	A change in Interconnection frequency.
Frequency Error [Archive]		2/8/2005	3/16/2007	The difference between the actual and scheduled frequency. (F_A – F_S)
Frequency Regulation [Archive]		2/8/2005	3/16/2007	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response [Archive]		2/8/2005	3/16/2007	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Response Measure [Archive]	FRM	2/7/2013	1/16/2014 (Becomes effective 4/1/15)	The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.
Frequency Response Obligation [Archive]	FRO	2/7/2013	1/16/2014 (Becomes effective 4/1/15)	The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Response Sharing Group [Archive]	FRSG	2/7/2013	1/16/2014 (Becomes effective 4/1/15)	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Generator Operator [Archive]	GOP	2/8/2005	3/16/2007	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner [Archive]	GO	2/8/2005	3/16/2007	Entity that owns and maintains generating units.
Generator Shift Factor [Archive]	GSF	2/8/2005	3/16/2007	A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor [Archive]	GLDF	2/8/2005	3/16/2007	The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement [Archive]	GCIR	11/13/2008	11/24/2009	The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Host Balancing Authority [Archive]		2/8/2005	3/16/2007	1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value [Archive]		2/8/2005	3/16/2007	Data measured on a Clock Hour basis.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Implemented Interchange [Archive]		5/2/2006	3/16/2007	The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange [Archive]		2/8/2005	3/16/2007	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. $(I_A - I_S)$
Independent Power Producer [Archive]	IPP	2/8/2005	3/16/2007	Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc. [Archive]	IEEE	2/7/2006	3/16/2007	

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interactive Remote Access [Archive]		11/26/12	11/22/2013 (Becomes effective 4/1/16)	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.
Interchange [Archive]		5/2/2006	3/16/2007	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority [Archive]	IA	5/2/2006	3/16/2007	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Distribution Calculator [Archive]	IDC	2/8/2005	3/16/2007	The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange Schedule [Archive]		2/8/2005	3/16/2007	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction [Archive]		2/8/2005	3/16/2007	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag [Archive]		2/8/2005	3/16/2007	The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service [Archive]		2/8/2005	3/16/2007	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection [Archive]		2/8/2005	3/16/2007	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection [Archive]		8/15/2013		When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Interconnection Reliability Operating Limit [Archive]	IROL	2/8/2005	3/16/2007 Retired 12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnection Reliability Operating Limit [Archive]	IROL	11/1/2006	12/27/2007	A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages[4] that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T_v [Archive]	IROL T_v	11/1/2006	12/27/2007	The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.
Intermediate Balancing Authority [Archive]		2/8/2005	3/16/2007	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.
Intermediate Balancing Authority [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
Intermediate System [Archive]		11/26/12	11/22/2013 (Becomes effective 4/1/2016)	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.

[4] On September 13, 2012, FERC issued an Order approving NERC's request to modify the reference to "Cascading Outages" to "Cascading outages" within the definition of IROL due to the fact that the definition of "Cascading Outages" was previously remanded by FERC.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interpersonal Communication [Archive]		11/7/2012		Any medium that allows two or more individuals to interact, consult, or exchange information.
Interruptible Load or Interruptible Demand [Archive]		11/1/2006	3/16/2007	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control [Archive]		2/8/2005	3/16/2007	Automatic Generation Control of jointly owned units by two or more Balancing Authorities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Limiting Element [Archive]		2/8/2005	3/16/2007	The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
Load [Archive]		2/8/2005	3/16/2007	An end-use device or customer that receives power from the electric system.
Load Shift Factor [Archive]	LSF	2/8/2005	3/16/2007	A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity [Archive]	LSE	2/8/2005	3/16/2007	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon [Archive]		8/4/2011	10/17/2013 (Becomes effective 1/1/15)	Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Market Flow [Archive]		11/4/2010	4/21/2011	The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Minimum Vegetation Clearance Distance [Archive]	MVCD	11/3/2011	3/21/2013 (Becomes effective 7/1/14)	The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Misoperation [Archive]		2/7/2006	3/16/2007	• Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. • Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). • Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.
Native Balancing Area [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Load [Archive]		2/8/2005	3/16/2007	The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon [Archive]		1/24/2011	11/17/2011	The transmission planning period that covers Year One through five.
Net Actual Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load [Archive]		2/8/2005	3/16/2007	Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange [Archive]		2/8/2005	3/16/2007	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service [Archive]		2/8/2005	3/16/2007	Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Non-Consequential Load Loss [Archive]		8/4/2011	10/17/2013 (Becomes effective 1/1/15)	Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service [Archive]		2/8/2005	3/16/2007	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve [Archive]		2/8/2005	3/16/2007	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing [Archive]		11/1/2006	12/27/2007	A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating [Archive]		2/8/2005	3/16/2007	The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator [Archive]		5/2/2007	10/16/2008	Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power) [Archive]		5/2/2007	10/16/2008	The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Nuclear Plant Licensing Requirements [Archive]	NPLRs	5/2/2007	10/16/2008	Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Interface Requirements [Archive]	NPIRs	5/2/2007	10/16/2008	The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Off-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak [Archive]		2/8/2005	3/16/2007	Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service [Archive]	OASIS	2/8/2005	3/16/2007	An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff [Archive]	OATT	2/8/2005	3/16/2007	Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Instruction [Archive]		5/6/2014		A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Plan [Archive]		2/7/2006	3/16/2007	A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.
Operating Procedure [Archive]		2/7/2006	3/16/2007	A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process [Archive]		2/7/2006	3/16/2007	A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve [Archive]		2/8/2005	3/16/2007	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operating Reserve – Spinning [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Reserve – Supplemental [Archive]		2/8/2005	3/16/2007	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage [Archive]		2/7/2006	3/16/2007	The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis [Archive]		10/17/2008	3/17/2011	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operational Planning Analysis [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Operations Support Personnel [Archive]		2/6/2014	6/19/2014 (effective 7/1/2016)	Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time operations of the Bulk Electric System.
Outage Transfer Distribution Factor [Archive]	OTDF	8/22/2008	11/24/2009	In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).
Overlap Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Participation Factors [Archive]		8/22/2008	11/24/2009	A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand [Archive]		2/8/2005	3/16/2007	1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period [Archive]		2/7/2006	3/16/2007	The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Access Control Systems [Archive]	PACS	11/26/12	11/22/2013 (Becomes effective 4/1/16)	Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Security Perimeter [Archive]	PSP	5/2/2006	1/18/2008 (Becomes inactive 3/31/16)	The physical, completely enclosed (“six-wall”) border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Physical Security Perimeter [Archive]	PSP	11/26/12	11/22/2013 (Becomes effective 4/1/16)	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Planning Assessment [Archive]		8/4/2011	10/17/2013 (Becomes effective 1/1/15)	Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority [Archive]	PA	2/8/2005	3/16/2007	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator [Archive]	PC	8/22/2008	11/24/2009	See Planning Authority.
Point of Delivery [Archive]	POD	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt [Archive]	POR	2/8/2005	3/16/2007	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service [Archive]	PTP	2/8/2005	3/16/2007	The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback [Archive]		08/22/2008	Not approved; Modification directed 11/24/09	Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Power Transfer Distribution Factor [Archive]	PTDF	08/22/2008	11/24/2009	In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pro Forma Tariff [Archive]		2/8/2005	3/16/2007	Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protected Cyber Assets [Archive]	PCA	11/26/12	11/22/2013 (Becomes effective 4/1/16)	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP. A Cyber Asset is not a Protected Cyber Asset if, for 30 consecutive calendar days or less, it is connected either to a Cyber Asset within the ESP or to the network within the ESP, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Protection System [Archive]		2/7/2006	3/17/2007 retired 4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System [Archive] [Implementation Plan]		11/19/2010	2/3/2012 (Became effective on 4/1/13)	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program [Archive]	PSMP	11/7/2012	12/19/2013 (Becomes effective 4/1/2015)	An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program [Archive]	PSMP	11/7/2013		An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Pseudo-Tie [Archive]		2/8/2005	3/16/2007	A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Pseudo-Tie [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Purchasing-Selling Entity [Archive]	PSE	2/8/2005	3/16/2007	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp [Archive]		2/8/2005	3/16/2007	(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions [Archive]		2/7/2006	3/16/2007	The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rating [Archive]		2/8/2005	3/16/2007	The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology [Archive]		08/22/2008	11/24/2009	The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reactive Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.
Reallocation [Archive]		2/8/2005	3/16/2007	The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time [Archive]		2/7/2006	3/16/2007	Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment [Archive]		10/17/2008	3/17/2011	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Receiving Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Regional Reliability Organization [Archive]	RRO	2/8/2005	3/16/2007	1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan [Archive]		2/8/2005	3/16/2007	The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve [Archive]		2/8/2005	3/16/2007	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Reserve Sharing Group [Archive]		8/15/2013		A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.
Regulation Service [Archive]		2/8/2005	3/16/2007	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment Arranged Interchange [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Adjustment RFI [Archive]		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.
Reliability Coordinator [Archive]	RC	2/8/2005	3/16/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area [Archive]		2/8/2005	3/16/2007	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System [Archive]	RCIS	2/8/2005	3/16/2007	The system that Reliability Coordinators use to post messages and share operating information in real time.
Reliability Directive [Archive]		8/16/2012		A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Standard [Archive]		5/9/2013	7/9/2013	A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
Reliable Operation [Archive]		5/9/2013	7/9/2013	Operating the elements of the bulk-power system [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Remedial Action Scheme [Archive]	RAS	2/8/2005	3/16/2007	See "Special Protection System"

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reportable Cyber Security Incident [Archive]		11/26/12	11/22/2013 (Becomes effective 4/1/16)	A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.
Reportable Disturbance [Archive]		2/8/2005	3/16/2007	Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE [Archive]		8/15/2013		The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC). Reporting ACE is calculated as follows: $\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$ Reporting ACE is calculated in the Western Interconnection as follows: $\text{Reporting ACE} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$ Where: **NI_A (Actual Net Interchange)** is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule. **NI_S (Scheduled Net Interchange)** is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE **(Continued)**				Interchange Actual. **B (Frequency Bias Setting)** is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority. **10** is the constant factor that converts the frequency bias setting units to MW/Hz. **F_A (Actual Frequency)** is the measured frequency in Hz. **F_S (Scheduled Frequency)** is 60.0 Hz, except during a time correction. **I_{ME} (Interchange Meter Error)** is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours). **I_{ATEC} (Automatic Time Error Correction)** is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection. $I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode. **I_{ATEC}** shall be zero when operating in any other AGC mode. • Y = B / BS. • H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3. • BS = Frequency Bias for the Interconnection (MW / 0.1 Hz).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE **(Continued)**				• Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B * ΔTE/6) • II_{actual} is the hourly Inadvertent Interchange for the last hour. • ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where: $\Delta TE = TE_{end}$ hour $- TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$ • TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks. • t is the number of minutes of Manual Time Error Correction that occurred during the hour. • TE_{offset} is 0.000 or +0.020 or -0.020. • PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required. Where: $PII_{accum}^{on/off\ peak}$ = last period's $PII_{accum}^{on/off\ peak}$ + PII_{hourly} All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE **(Continued)**				consistent with the measures included in this standard. 1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses. 2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times. 3. The use of a common Scheduled Frequency FS for all areas at all times. 4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)
Request for Interchange [Archive]	RFI	5/2/2006	3/16/2007	A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Request for Interchange [Archive]	RFI	2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reserve Sharing Group [Archive]	RSG	2/8/2005	3/16/2007	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Reserve Sharing Group Reporting ACE [Archive]		8/15/2013		At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Reserve Sharing Group at the time of measurement.
Resource Planner [Archive]	RP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Response Rate [Archive]		2/8/2005	3/16/2007	The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way [Archive]	ROW	2/7/2006	3/16/2007	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Right-of-Way [Archive]	ROW	11/3/2011	3/21/2013 (Becomes inactive 6/30/2014)	The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.
Right-of-Way [Archive]	ROW	5/9/12	3/21/2013 (Becomes effective 7/1/2014)	The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Scenario [Archive]		2/7/2006	3/16/2007	Possible event.
Schedule [Archive]		2/8/2005	3/16/2007	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency [Archive]		2/8/2005	3/16/2007	60.0 Hertz, except during a time correction.
Scheduling Entity [Archive]		2/8/2005	3/16/2007	An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path [Archive]		2/8/2005	3/16/2007	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority exporting the Interchange.
Sink Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Sink Balancing Authority [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Source Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority [Archive]		2/6/2014	6/30/2014 (Becomes effective 10/1/2014)	The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
Special Protection System (Remedial Action Scheme) [Archive]	SPS	2/8/2005	3/16/2007	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spinning Reserve [Archive]		2/8/2005	3/16/2007	Unloaded generation that is synchronized and ready to serve additional demand.
Stability [Archive]		2/8/2005	3/16/2007	The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit [Archive]		2/8/2005	3/16/2007	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Supervisory Control and Data Acquisition [Archive]	SCADA	2/8/2005	3/16/2007	A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service [Archive]		2/8/2005	3/16/2007	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge [Archive]		2/8/2005	3/16/2007	A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage [Archive]		2/7/2006	3/16/2007	The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System [Archive]		2/8/2005	3/16/2007	A combination of generation, transmission, and distribution components.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
System Operating Limit [Archive]	SOL	2/8/2005	3/16/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator [Archive]		2/8/2005	3/16/2007	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
System Operator [Archive]		2/6/2014	6/19/2014 (effective 7/1/2016)	An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time.
Telemetering [Archive]		2/8/2005	3/16/2007	The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating [Archive]		2/8/2005	3/16/2007	The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line [Archive]		2/8/2005	3/16/2007	A circuit connecting two Balancing Authority Areas.
Tie Line Bias [Archive]		2/8/2005	3/16/2007	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error [Archive]		2/8/2005	3/16/2007	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Time Error Correction [Archive]		2/8/2005	3/16/2007	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.
TLR (Transmission Loading Relief)[5] Log [Archive]		2/8/2005	3/16/2007	Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability [Archive]	TFC	08/22/2008	11/24/2009	The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Internal Demand [Archive]		5/6/2014		The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.
Total Transfer Capability [Archive]	TTC	2/8/2005	3/16/2007	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction [Archive]		2/8/2005	3/16/2007	See Interchange Transaction.

[5] NERC added the spelled out term for TLR Log for clarification purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transfer Capability [Archive]		2/8/2005	3/16/2007	The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not generally* equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor [Archive]		2/8/2005	3/16/2007	See Distribution Factor.
Transmission [Archive]		2/8/2005	3/16/2007	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint [Archive]		2/8/2005	3/16/2007	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer [Archive]		2/8/2005	3/16/2007	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Line [Archive]		2/7/2006	3/16/2007	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator [Archive]	TOP	2/8/2005	3/16/2007	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Operator Area [Archive]		08/22/2008	11/24/2009	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner [Archive]	TO	2/8/2005	3/16/2007	The entity that owns and maintains transmission facilities.
Transmission Planner [Archive]	TP	2/8/2005	3/16/2007	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Reliability Margin [Archive]	TRM	2/8/2005	3/16/2007	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Transmission Reliability Margin Implementation Document [Archive]	TRMID	08/22/2008	11/24/2009	A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service [Archive]		2/8/2005	3/16/2007	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider [Archive]	TSP	2/8/2005	3/16/2007	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Vegetation [Archive]		2/7/2006	3/16/2007	All plant material, growing or not, living or dead.
Vegetation Inspection [Archive]		2/7/2006	3/16/2007	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection [Archive]		11/3/2011	3/21/2013 (Becomes inactive 6/30/2014)	The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Vegetation Inspection [Archive]		5/9/12	3/21/2013 (Becomes effective 7/1/2014)	The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Wide Area [Archive]		2/8/2005	3/16/2007	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.
Year One [Archive]		1/24/2011	11/17/2011	The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

ERCOT Regional Definitions

The following terms were developed as regional definitions for the ERCOT region:

ERCOT Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Frequency Measurable Event [Archive]	FME	8/15/2013	1/16/2014 (Becomes effective 4/1/14)	An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions: i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year). Or ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).
Governor [Archive]		8/15/2013	1/16/2014 (Becomes effective	The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.

ERCOT Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
			4/1/14)	
Primary Frequency Response [Archive]	PFR	8/15/2013	1/16/2014 (Becomes effective 4/1/14)	The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

NPCC Regional Definitions

The following definitions were developed for use in NPCC Regional Standards.

NPCC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Current Zero Time [Archive]		11/04/2010	10/20/2011	The time of the final current zero on the last phase to interrupt.
Generating Plant [Archive]		11/04/2010	10/20/2011	One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

Reliability*First* Regional Definitions

The following definitions were developed for use in Reliability*First* Regional Standards.

RFC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Resource Adequacy [Archive]		08/05/2009	03/17/2011	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand [Archive]		08/05/2009	03/17/2011	Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period [Archive]		08/05/2009	03/17/2011	A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Wind Generating Station [Archive]		11/03/2011		A collection of wind turbines electrically connected together and injecting energy into the grid at one point, sometimes known as a "Wind Farm."
Year One [Archive]		08/05/2009	03/17/2011	The planning year that begins with the upcoming annual Peak Period

WECC Regional Definitions

The following definitions were developed for use in WECC Regional Standards.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Area Control Error† [Archive]	ACE	3/12/2007	6/8/2007 (Becomes inactive 3/31/14)	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control‡ [Archive]	AGC	3/12/2007	6/8/2007	Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction [Archive]		3/26/2008	5/21/2009 (Becomes inactive 3/31/14)	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Automatic Time Error Correction [Archive]		12/19/2012	10/16/2013 (Becomes effective 4/1/2014)	The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.
Average Generation‡ [Archive]		3/12/2007	6/8/2007	Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day‡ [Archive]		3/12/2007	6/8/2007	Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Commercial Operation [Archive]		10/29/2008	4/21/2011	Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Contributing Schedule [Archive]		2/10/2009	3/17/2011	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Dependability-Based Misoperation [Archive]		10/29/2008	4/21/2011	Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Disturbance[‡] [Archive]		3/12/2007	6/8/2007	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Extraordinary Contingency† [Archive]		3/12/2007	6/8/2007	Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: *means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).*
Frequency Bias† [Archive]		3/12/2007	6/8/2007	Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Functionally Equivalent Protection System [Archive]	FEPS	10/29/2008	4/21/2011	A Protection System that provides performance as follows: • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.
Functionally Equivalent RAS [Archive]	FERAS	10/29/2008	4/21/2011	A Remedial Action Scheme ("RAS") that provides the same performance as follows: • Each RAS can detect the same conditions and provide

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
				mitigation to comply with all Reliability Standards. • Each RAS may have different components and operating characteristics.
Generating Unit Capability[±] [Archive]		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve[±] [Archive]		3/12/2007	6/8/2007	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating[±] [Archive]		3/12/2007	6/8/2007	Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.
Operating Reserve[±] [Archive]		3/12/2007	6/8/2007	Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit[±] [Archive]	OTC	3/12/2007	6/8/2007	Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Primary Inadvertent Interchange [Archive]		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Qualified Controllable Device [Archive]		2/10/2009	3/17/2011	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.
Qualified Transfer Path [Archive]		2/10/2009	3/17/2011	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.
Qualified Transfer Path Curtailment Event [Archive]		2/10/2009	3/17/2011	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.
Relief Requirement [Archive]		2/10/2009	3/17/2011 (Becomes inactive 6/30/2014)	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Relief Requirement [Archive]		2/7/2013	6/13/2014 (Becomes effective 7/1/2014)	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages determined in the WECC unscheduled flow mitigation guideline.
Secondary Inadvertent		3/26/2008	5/21/2009	The component of area (n) inadvertent interchange caused by

WECC Regional Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interchange [Archive]				the regulating deficiencies of area (i).
Security-Based Misoperation [Archive]		10/29/2008	4/21/2011	A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.
Spinning Reserve[†] [Archive]		3/12/2007	6/8/2007	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).
Transfer Distribution Factor [Archive]	TDF	2/10/2009	3/17/2011	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
WECC Table 2[†] [Archive]		3/12/2007	6/8/2007	Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

Endnotes

[†] FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.

Exhibit B

Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

EXHIBIT B: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

EOP-010-1- To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.

Applicability:

- Reliability Coordinator
- Transmission Operator with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

Reliability Standard EOP-010-1 includes three requirements and with a quorum of 86.90%, received an approval of 91.95%.

On November 13, 2013 NERC submitted a petition for approval of EOP-010-1 to the Federal Energy Regulatory Commission ("FERC") and on June 19, 2014, FERC approved the standard.

EXHIBIT B: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

INT-004-3- To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.

Applicability:

- Balancing Authority
- Purchasing-Selling Entity

Reliability Standard INT-004-3 includes three requirements and with a quorum of 83.88%, received an approval of 83.44%.

On February 27, 2014 NERC submitted a petition for approval of INT-004-3 to the Federal Energy Regulatory Commission ("FERC") and on June 30, 2014, FERC approved the standard.

EXHIBIT B: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

INT-006-4- To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.

Applicability:

- Balancing Authority
- Transmission Service Provider

Reliability Standard INT-006-4 includes five requirements and a table that sets forth timing requirements for all of the Interconnections. Reliability Standard INT-006-4 received a quorum of 85.07% and an approval of 80.77%

On February 27, 2014 NERC submitted a petition for approval of INT-006-4 to the Federal Energy Regulatory Commission ("FERC") and on June 30, 2014, FERC approved the standard.

EXHIBIT B: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

INT-009-2- To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.

Applicability:

- Balancing Authority

Reliability Standard INT-009-2 includes three requirements and with a quorum of 85.07%, received an approval of 72.86%.

On February 27, 2014 NERC submitted a petition for approval of INT-009-2 to the Federal Energy Regulatory Commission ("FERC") and on June 30, 2014, FERC approved the standard.

EXHIBIT B: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

INT-010-2- To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.

Applicability:

- Balancing Authority

Reliability Standard INT-010-2 includes three requirements and with a quorum of 83.58%, received an approval of 91.51%.

On February 27, 2014 NERC submitted a petition for approval of INT-010-2 to the Federal Energy Regulatory Commission ("FERC") and on June 30, 2014, FERC approved the standard.

EXHIBIT B: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

INT-011-1- To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.

Applicability:

- Load-Serving Entities

Reliability Standard INT-011-1 includes one requirement and with a quorum of 84.78%, received an approval of 72.91%.

On February 27, 2014, NERC submitted a petition for approval of INT-011-1 to the Federal Energy Regulatory Commission (“FERC”) and on June 30, 2014 FERC approved the standard.

EXHIBIT B: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

MOD-032-1- To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

Applicability:

- Balancing Authority
- Generator Owner
- Load Serving Entity
- Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)
- Resource Planner
- Transmission Owner
- Transmission Planner
- Transmission Service Provider

Reliability Standard MOD-032-1 includes three requirement and a table that sets forth data reporting requirements. Reliability Standard MOD-032-1 received a quorum of 87.53% and an approval of 77.49%.

On February 25, 2014, NERC submitted a petition for approval of MOD-32-1 to the Federal Energy Regulatory Commission (“FERC”) and on May 1, 2014 FERC approved the standard.

EXHIBIT B: Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Second Quarter 2014

MOD-033-1- To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

Applicability:

- Planning Authority and Planning Coordinator (hereafter referred to as "Planning Coordinator")
- Reliability Coordinator
- Transmission Operator

Reliability Standard MOD-033-1 includes two requirements and with a quorum of 82.49%, received an approval of 82.45%.

On February 25, 2014, NERC submitted a petition for approval of MOD-33-1 to the Federal Energy Regulatory Commission ("FERC") and on May 1, 2014 FERC approved the standard.

Exhibit C: List of Currently Effective NERC Reliability Standards

EXHIBIT C

Resource and Demand Balancing (BAL)	
BAL-001-1	Real Power Balancing Control Performance
BAL-001-TRE-1	Primary Frequency Response in the ERCOT Region
BAL-002-1	Disturbance Control Performance
BAL-003-0.1b	Frequency Response and Bias
BAL-004-0	Time Error Correction
BAL-004-WECC-02	Automatic Time Error Correction (ATEC)
BAL-005-0.2b	Automatic Generation Control
BAL-006-2	Inadvertent Interchange
BAL-502-RFC-02	Planning Resource Adequacy Analysis, Assessment and Documentation
BAL-STD-002-0	Operating Reserves (WECC)
Communications (COM)	
COM-001-1.1	Telecommunications
COM-002-2	Communications and Coordination
Critical Infrastructure Protection (CIP)	
CIP-002-3	Cyber Security — Critical Cyber Asset Identification
CIP-003-3	Cyber Security — Security Management Controls
CIP-004-3a	Cyber Security — Personnel & Training
CIP-005-3a	Cyber Security — Electronic Security Perimeter(s)
CIP-006-3c	Cyber Security — Physical Security of Critical Cyber Assets
CIP-007-3a	Cyber Security — Systems Security Management
CIP-008-3	Cyber Security — Incident Reporting and Response Planning
CIP-009-3	Cyber Security — Recovery Plans for Critical Cyber Assets
Emergency Preparedness and Operations (EOP)	
EOP-001-2.1b	Emergency Operations Planning
EOP-002-3.1	Capacity and Energy Emergencies
EOP-003-2	Load Shedding Plans
EOP-004-2	Event Reporting
EOP-005-2	System Restoration from Blackstart Resources
EOP-006-2	System Restoration Coordination
EOP-008-1	Loss of Control Center Functionality

Facilities Design, Connections, and Maintenance (FAC)	
FAC-001-1	Facility Connection Requirements
FAC-002-1	Coordination of Plans For New Generation, Transmission, and End-User Facilities
FAC-003-3	Transmission Vegetation Management
FAC-008-3	Facility Ratings
FAC-010-2.1	System Operating Limits Methodology for the Planning Horizon
FAC-011-2	System Operating Limits Methodology for the Operations Horizon
FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon
FAC-014-2	Establish and Communicate System Operating Limits
FAC-501-WECC-1	Transmission Maintenance
Interchange Scheduling and Coordination (INT)	
INT-001-3	Interchange Information
INT-003-3	Interchange Transaction Implementation
INT-004-2	Dynamic Interchange Transaction Modifications
INT-005-3	Interchange Authority Distributes Arranged Interchange
INT-006-3	Response to Interchange Authority
INT-007-1	Interchange Confirmation
INT-008-3	Interchange Authority Distributes Status
INT-009-1	Implementation of Interchange
INT-010-1	Interchange Coordination Exemptions
Interconnection Reliability Operations and Coordination (IRO)	
IRO-001-1.1	Reliability Coordination — Responsibilities and Authorities
IRO-002-2	Reliability Coordination — Facilities
IRO-003-2	Reliability Coordination — Wide-Area View
IRO-004-2	Reliability Coordination — Operations Planning
IRO-005-3.1a	Reliability Coordination — Current Day Operations
IRO-006-5	Reliability Coordination — Transmission Loading Relief (TLR)
IRO-006-EAST-1	Transmission Loading Relief Procedure for the Eastern Interconnection
IRO-006-TRE-1	IROL and SOL Mitigation in the ERCOT Region
IRO-006-WECC-1	Qualified Transfer Path Unscheduled Flow (USF) Relief

IRO-008-1	Reliability Coordinator Operational Analyses and Real-time Assessments
IRO-009-1	Reliability Coordinator Actions to Operate Within IROLs
IRO-010-1a	Reliability Coordinator Data Specification and Collection
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
IRO-015-1	Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1	Coordination of Real-time Activities Between Reliability Coordinators
Modeling, Data, and Analysis (MOD)	
MOD-001-1a	Available Transmission System Capability
MOD-004-1	Capacity Benefit Margin
MOD-008-1	Transmission Reliability Margin Calculation Methodology
MOD-010-0	Steady-State Data for Modeling and Simulation of the Interconnected Transmission System
MOD-012-0	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0	Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management
MOD-020-0	Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts
MOD-026-1	Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
MOD-027-1	Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
MOD-028-2	Area Interchange Methodology
MOD-029-1a	Rated System Path Methodology
MOD-030-2	Flowgate Methodology
Nuclear (NUC)	
NUC-001-2.1	Nuclear Plant Interface Coordination

Personnel Performance, Training, and Qualifications (PER)	
PER-001-0.2	Operating Personnel Responsibility and Authority
PER-003-1	Operating Personnel Credentials
PER-004-2	Reliability Coordination — Staffing
PER-005-1	System Personnel Training

Protection and Control (PRC)	
PRC-001-1.1	System Protection Coordination
PRC-002-NPCC-01	Disturbance Monitoring
PRC-004-2.1a	Analysis and Mitigation of Transmission and Generation Protection System Misoperations
PRC-004-WECC-1	Protection System and Remedial Action Scheme Misoperation
PRC-005-1.1b	Transmission and Generation Protection System Maintenance and Testing
PRC-006-1	Automatic Underfrequency Load Shedding
PRC-006-SERC-01	Automatic Underfrequency Load Shedding Requirements
PRC-008-0	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program
PRC-010-0	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program
PRC-011-0	Undervoltage Load Shedding System Maintenance and Testing
PRC-015-0	Special Protection System Data and Documentation
PRC-016-0.1	Special Protection System Misoperations
PRC-017-0	Special Protection System Maintenance and Testing
PRC-018-1	Disturbance Monitoring Equipment Installation and Data Reporting
PRC-021-1	Under-Voltage Load Shedding Program Data
PRC-022-1	Under-Voltage Load Shedding Program Performance
PRC-023-1	Transmission Relay Loadability
PRC-023-2	Transmission Relay Loadability

Transmission Operations (TOP)	
TOP-001-1a	Reliability Responsibilities and Authorities
TOP-002-2.1b	Normal Operations Planning
TOP-003-1	Planned Outage Coordination

TOP-004-2	Transmission Operations
TOP-005-2a	Operational Reliability Information
TOP-006-2	Monitoring System Conditions
TOP-007-0	Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
TOP-007-WECC-1	System Operating Limits
TOP-008-1	Response to Transmission Limit Violations
Transmission Planning (TPL)	
TPL-001-0.1	System Performance Under Normal (No Contingency) Conditions (Category A)
TPL-002-0b	System Performance Following Loss of a Single Bulk Electric System Element (Category B)
TPL-003-0b	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
TPL-004-0a	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
Voltage and Reactive (VAR)	
VAR-001-3	Voltage and Reactive Control
VAR-002-2b	Generator Operation for Maintaining Network Voltage Schedules
VAR-002-WECC-1	Automatic Voltage Regulators (AVR)
VAR-501-WECC-1	Power System Stabilizer (PSS)