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Exhibit A

Exhibit A-1 Reliability Standards Applicable to Nova Scotia, Approved by FERC in Third Quarter 2016

Exhibit A-2 Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved by FERC in Third Quarter 2016

Exhibit A-3 Reliability Standards Filed for Approval

Exhibit B List of Currently Effective NERC Reliability Standards

Exhibit C Updated *Glossary of Terms Used in NERC Reliability Standards*

FERC (**Exhibit B**); and (v) an updated *NERC Glossary* as approved by FERC (**Exhibit C**).¹

I. NOTICE 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

Pursuant to Section 215 of the Federal Power Act,² NERC has been certified by the Commission as the Electric Reliability Organization (“ERO”) in the United States.³ During the third quarter of 2016, the Commission approved the Reliability Standard contained in **Exhibit A** as mandatory and enforceable for users, owners, and operators of the BPS within the United States. Some or all of NERC’s Reliability Standards are also mandatory in the Canadian provinces of Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Québec, and Saskatchewan.

¹ The list of Reliability Standards and NERC Glossary in **Exhibit B** and **Exhibit C** were generated on or around the date of this filing, and, given the quarterly schedule on which this application is filed, these lists may include standards and definitions that became effective or were approved after the final day of the previous quarter. Only those standards and definitions highlighted for NSUARB in the present quarterly application and all previous applications should be considered for purposes of this application.

² 16 U.S.C. § 824o(f) (2012) (entrusting 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 Electric Reliability Organization to develop mandatory and enforceable Reliability Standards, subject to FERC review and approval).

³ FERC certified NERC as the electric reliability organization (“ERO”) authorized by Section 215 of the Federal Power Act, in its order issued on July 20, 2006, in Docket No. RR06-1-000. *See Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006), *order on reh’g and compliance*, 117 FERC ¶ 61,126 (2006), *aff’d sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

NERC entered into a Memorandum of Understanding (“MOU”) with the NSUARB,⁴ and a separate MOU with Nova Scotia Power Incorporated (“NSPI”) and the Northeast Power Coordinating Council, Inc. (“NPCC”),⁵ to provide reliability services to Nova Scotia. These MOUs became effective on December 22, 2006 and May 11, 2010, respectively. The December 22, 2006 MOU memorializes the relationship between NERC and the NSUARB formed to improve the reliability of the North American BPS. 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.

On June 30, 2010, NERC submitted its first set of Reliability Standards and the *NERC Glossary* to the NSUARB, and on July 20, 2011, NSUARB issued a decision approving these documents.⁶ In that decision, the NSUARB approved a “quarterly review” process for considering new and amended NERC Reliability Standards and criteria⁷ and ordered that “applications will not be processed by the Board until [FERC] has approved or remanded the standards in the United States.”⁸ The NSUARB Decision also stated that NSUARB approval is not required for the Violation Risk Factors (“VRFs”) and Violation Severity Levels (“VSLs”) associated with proposed Reliability Standards, but the NSUARB noted that it will accept VRFs and VSLs as guidance.⁹

⁴ See Memorandum of Understanding between Nova Scotia Utility and Review Board and North American Electric Reliability Corporation (signed Dec. 22, 2006).

⁵ 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).

⁶ *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”).

⁷ *Id.* at P 30.

⁸ *Id.*

⁹ *Id.* at P 33.

Based on the NSUARB Decision, NERC applications to the NSUARB only request approval for those Reliability Standards and Glossary definitions approved by FERC during the previous quarter. NERC does not seek formal approval of VRFs and VSLs associated with the Reliability Standards submitted in its quarterly applications. Rather, for informational purposes and for guidance, NERC provides a link below to the FERC-approved VRFs and VSLs associated with NERC Reliability Standards.¹⁰ NERC does not include in its applications 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 records 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 BPS. 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, through the balloting process, have approved the Reliability Standard provided in **Exhibit A**, and the standards have been adopted by the NERC Board of Trustees.

NERC develops Reliability Standards and associated definitions in accordance with Section 300 (Reliability Standards Development) and Appendix 3A (Standards Processes

¹⁰ NERC's VRF Matrix and VSL Matrix are available at: <http://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United States>. See left-hand side of webpage for downloadable documents.

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*, most recently updated September 29, 2016, contains 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. NERC submits the *NERC Glossary* as **Exhibit C** of this application for informational purposes.

C. Description of Proposed Definitions and Reliability Standards, Third Quarter 2016

As explained below, the following two FERC orders were issued in the third quarter of 2016 approving three NERC Reliability Standards: (1) a delegated letter order approving Reliability Standards IRO-018-1 and TOP-010-1, issued on September 22, 2016;¹² and (2) an order approving Reliability Standard TPL-007-1 and one definition, issued on September 22, 2016.¹³

Reliability Standard	Effective Date
Interconnection Reliability Operations and Coordination (IRO) Standard	
IRO-018-1*	4/1/2018
Transmission Operations (TOP) Standard	
TOP-010-1*	4/1/2018
Transmission Planning (TPL) Standard	
TPL-007-1*	7/1/2017

* 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. IRO-018-1 and TOP-010-1

On May 26, 2016, FERC approved Reliability Standards IRO-018-1 (Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities), and TOP-010-1 (Real-

¹¹ The NERC *Rules of Procedure* are available at: <http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>.

¹² *N. Am. Elec. Reliability Corp.*, 156 FERC ¶ 61,207 (2016), Docket No. RD16-6-000 (Sept. 22, 2016) (unpublished letter order).

¹³ Order No. 830, *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 156 FERC ¶ 61,215, 81 Fed. Reg. 67120 (2016).

time Reliability Monitoring and Analysis Capabilities), as well as an associated implementation plan and VRFs (with exceptions) and VSLs. The Commission directed NERC in its order to “submit a compliance filing within 60 days of the date the order was issued to modify the VRF designations for Requirement R1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1 to “high.”¹⁴ Reliability Standards IRO-018-1 and TOP-010-1 improve real-time situational awareness capabilities and enhance reliable operations by requiring Reliability Coordinators, Transmission Operators, and Balancing Authorities to provide operators with an improved awareness of system conditions analysis capabilities, including alarm availability, so that operators may take appropriate steps to ensure reliability. Reliability Standard IRO-018-1 is applicable to Reliability Coordinators. Reliability Standard TOP-010-1 applies to Transmission Operators and Balancing Authorities.

2. TPL-007-1

On January 21, 2015, FERC approved Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events), associated implementation plan, VRFs and VSLs, and a new definition Transmission System Planned Performance for Geomagnetic Disturbance Events to be included in the *NERC Glossary*, attached herein as **Exhibit C**. Reliability Standard TPL-007-1 establishes requirements for certain registered entities to assess the vulnerability of their transmission systems to geomagnetic disturbance events (“GMDs”), which occur when the sun ejects charged particles that interact with and cause changes in the earth’s magnetic fields.

¹⁴ *N. Am. Elec. Reliability Corp.*, 156 FERC ¶ 61,207 (2016), Docket No. RD16-6-000 (Sept. 22, 2016) (unpublished letter order).

Reliability Standard TPL-007-1 requires applicable entities that do not meet certain performance requirements, based on the results of their vulnerability assessments, to develop a plan to achieve the requirements. In addition, Reliability Standard TPL-007-1 requires applicable entities to develop and implement corrective action plans to mitigate identified vulnerabilities.

III. CONCLUSION

NERC respectfully requests that the NSUARB approve the Reliability Standards and *NERC Glossary* definition as specified herein.

Respectfully submitted,

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Date: November 29, 2016

Exhibit A (1)

**Reliability Standard Applicable to Nova Scotia, Approved by FERC in Third
Quarter 2016**

**Exhibit A (1): Reliability Standard Applicable to Nova Scotia, Approved by FERC in
Third Quarter 2016**

Reliability Standard	Effective Date
Interconnection Reliability Operations and Coordination (IRO) Standard	
IRO-018-1*	4/1/2018
Transmission Operations (TOP) Standard	
TOP-010-1*	4/1/2018
Transmission Planning (TPL) Standard	
TPL-007-1*	7/1/2017

* 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.

Exhibit A (2)

**Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved
by FERC in Third Quarter 2016**

Exhibit A (2): Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved by FERC in Third Quarter 2016

IRO-018-1 - Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.

Applicability:

- **Functional Entities**
 - **Applicable Reliability Coordinators**

Reliability Standard IRO-018-1 includes three requirements.

On May 26, 2016, the North American Electric Reliability Corporation (“NERC”) filed a petition for approval of proposed Reliability Standard IRO-018-1 (Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities) with the Federal Energy Regulatory Commission (“FERC”) in Docket No. RD16-6-000. FERC approved IRO-018-1 on September 22, 2016.

Exhibit A (2): Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved by FERC in Third Quarter 2016

TOP-010-1 - Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.

Applicability:

- **Functional Entities**
 - **Applicable Transmission Operators**
 - **Applicable Balancing Authorities**

Reliability Standard TOP-010-1 includes four requirements.

On May 26, 2016, NERC filed a petition for approval of proposed Reliability Standard IRO-018-1 (Real-time Reliability Monitoring and Analysis Capabilities) with FERC in Docket No. RD16-6-000. FERC approved TOP-010-1 on September 22, 2016.

Exhibit A (2): Informational Summary of Each Reliability Standard Applicable to Nova Scotia, Approved by FERC in Third Quarter 2016

TPL-007-1 - Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

Applicability:

- **Functional Entities**
 - **Applicable Planning Coordinators** with a planning area that includes a Facility or Facilities
 - **Applicable Transmission Planners** with a planning area that includes a Facility or Facilities
 - **Applicable Transmission Owners** who owns a Facility or Facilities
 - **Applicable Generator Owners** who owns a Facility or Facilities
- **Facilities**
 - Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Reliability Standard TPL-007-1 includes seven requirements, several tables, and three figures.

On January 21, 2015, NERC filed a petition for approval of proposed Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events) with FERC in Docket No. RM15-11-000. FERC approved TPL-007-1 on September 22, 2016.

Exhibit A (3): Reliability Standards Filed for Approval

Reliability Standard IRO-018-1

A. Introduction

- 1. Title:** Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
- 2. Number:** IRO-018-1
- 3. Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1.** Reliability Coordinators
- 5. Effective Date:** See Implementation Plan

B. Requirements and Measures

- R1.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
 - 1.1.** Criteria for evaluating the quality of Real-time data;
 - 1.2.** Provisions to indicate the quality of Real-time data to the System Operator; and
 - 1.3.** Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.
- M1.** Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator or supporting logs, dated checklists, voice recordings, voice transcripts, or other evidence.
- R2.** Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
 - 2.1.** Criteria for evaluating the quality of analysis used in its Real-time Assessments;
 - 2.2.** Provisions to indicate the quality of analysis used in its Real-time Assessments; and

- 2.3.** Actions to address analysis quality issues affecting its Real-time Assessments.
- M2.** Each Reliability Coordinator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R2. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Reliability Coordinator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.
- R3.** Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- M3.** Each Reliability Coordinator shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

“Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) 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 it was compliant for the full-time period since the last audit.

The Reliability Coordinator shall 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.

The Reliability Coordinator shall retain evidence of compliance for Requirements R1 and R3 and Measures M1 and M3 for the current calendar year and one previous calendar year, with the exception of operator logs and

voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall retain evidence of compliance for Requirement R2 and Measure M2 for a rolling 30-day period, 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 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 Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of	The Reliability Coordinator's Operating Process or Operating Procedure to address the quality of

		analysis used in its Real-time Assessments did not include one of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include two of the elements listed in Part 2.1 through Part 2.3.	analysis used in its Real-time Assessments did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Reliability Coordinator did not implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments.
R3.	N/A	N/A	The Reliability Coordinator has an alarm process monitor but the alarm process monitor did not provide a notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The Reliability Coordinator does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

- [Implementation Plan](#)

Version History

Version	Date	Action	Change Tracking
1	October 30, 3015	New standard developed in Project 2009-02 to respond to recommendations in Real-time Best Practices Task Force Report and FERC directives.	N/A
1	May 5, 2016	Adopted by the Board of Trustees.	New

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The RC uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The RC's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed IRO-018-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the RC shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The RC's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the RC to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the RC;

Supplemental Material

- Following processes established for resolving data conflicts as specified in IRO-010-1a, IRO-010-2, or other applicable Reliability Standards;
- Taking corrective actions on the RC's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the RC's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R3

Requirement R3 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

Rationale for Requirement R1: The Reliability Coordinator (RC) uses a set of Real-time data identified in IRO-010-1a Requirement R1 and IRO-010-2 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the RC shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by IRO-010-2 Requirement R3 Part 3.2 provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R2: Requirement R2 ensures RCs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Rationale for Requirement R3: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard IRO-018-1 — Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities

United States

Standard	Requirement	Enforcement Date	Inactive Date
IRO-018-1	All	04/01/2018	

Reliability Standard TOP-010-1

A. Introduction

1. **Title:** Real-time Reliability Monitoring and Analysis Capabilities
2. **Number:** TOP-010-1
3. **Purpose:** Establish requirements for Real-time monitoring and analysis capabilities to support reliable System operations.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Transmission Operators
 - 4.1.2. Balancing Authorities
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

- R1.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
 - 1.1. Criteria for evaluating the quality of Real-time data;
 - 1.2. Provisions to indicate the quality of Real-time data to the System Operator; and
 - 1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments.
- M1.** Each Transmission Operator shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R1; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.
- R2.** Each Balancing Authority shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
 - 2.1. Criteria for evaluating the quality of Real-time data;
 - 2.2. Provisions to indicate the quality of Real-time data to the System Operator; and

- 2.3.** Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects its analysis functions.
- M2.** Each Balancing Authority shall have evidence that it implemented its Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R2; and 2) evidence the Balancing Authority implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.
- R3.** Each Transmission Operator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- 3.1.** Criteria for evaluating the quality of analysis used in its Real-time Assessments;
- 3.2.** Provisions to indicate the quality of analysis used in its Real-time Assessments; and
- 3.3.** Actions to address analysis quality issues affecting its Real-time Assessments.
- M3.** Each Transmission Operator shall have evidence it implemented its Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments as specified in Requirement R3. This evidence could include, but is not limited to: 1) an Operating Process or Operating Procedure in electronic or hard copy format meeting all provisions of Requirement R3; and 2) evidence the Transmission Operator implemented the Operating Process or Operating Procedure as called for in the Operating Process or Operating Procedure, such as dated operator logs, dated checklists, voice recordings, voice transcripts, or other evidence.
- R4.** Each Transmission Operator and Balancing Authority shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- M4.** Each Transmission Operator and Balancing Authority shall have evidence of an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. This evidence could include, but is not limited to, operator logs, computer printouts, system specifications, or other evidence.

C. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Enforcement Authority:**

“Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) 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 it was compliant for the full-time period since the last audit.

The applicable entity shall 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.

The applicable entity shall retain evidence of compliance for Requirements R1, R2, and R4, and Measures M1, M2, and M4 for the current calendar year and one previous calendar year, with the exception of operator logs and voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Operator shall retain evidence of compliance for Requirement R3 and Measure M3 for a rolling 30-day period, 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.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include one of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include two of the elements listed in Part 1.1 through Part 1.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments did not include any of the elements listed in Part 1.1 through Part 1.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments.
R2.	N/A	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the	The Balancing Authority's Operating Process or Operating Procedure to address the quality of the

		Real-time data necessary to perform its analysis functions and Real-time monitoring did not include one of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include two of the elements listed in Part 2.1 through Part 2.3.	Real-time data necessary to perform its analysis functions and Real-time monitoring did not include any of the elements listed in Part 2.1 through Part 2.3; OR The Balancing Authority did not implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its analysis functions and Real-time monitoring.
R3.	N/A	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include one of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include two of the elements listed in Part 3.1 through Part 3.3.	The Transmission Operator's Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments did not include any of the elements listed in Part 3.1 through Part 3.3; OR The Transmission Operator did not implement an Operating Process or Operating Procedure to address the quality of

				analysis used in its Real-time Assessments.
R4.	N/A	N/A	The responsible entity has an alarm process monitor but the alarm process monitor did not provide notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor occurred.	The responsible entity does not have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred.

D. Regional Variances

None.

E. Associated Documents

- [Implementation Plan](#)

Version History

Version	Date	Action	Change Tracking
1	October 30, 2015	New standard developed in Project 2009-02 to respond to recommendations in Real-time Best Practices Task Force Report and FERC directives.	N/A
1	May 5, 2016	Adopted by the Board of Trustees	New

Guidelines and Technical Basis

Real-time monitoring, or *monitoring* the Bulk Electric System (BES) in Real-time, is a primary function of Reliability Coordinators (RCs), Transmission Operators (TOPs), and Balancing Authorities (BAs) as required by TOP and IRO Reliability Standards. As used in TOP and IRO Reliability Standards, monitoring involves observing operating status and operating values in Real-time for awareness of system conditions. Real-time monitoring may include the following activities performed in Real-time:

- Acquisition of operating data;
- Display of operating data as needed for visualization of system conditions;
- Audible or visual alerting when warranted by system conditions; and
- Audible or visual alerting when monitoring and analysis capabilities degrade or become unavailable.

Requirement R1

The TOP uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform monitoring and Real-time Assessments appear in other Reliability Standards.

The TOP's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R1 Part 1.1. The criteria support identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 specifies the TOP shall include actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. Requirement R1 Part 1.3 is focused on addressing data point quality issues affecting Real-time Assessments. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R1 Part 1.3.

The TOP's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the TOP to meet its obligations for performing the Real-time Assessment. Examples of actions to address data quality issues include, but are not limited to, the following:

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- Notifying entities that provide Real-time data to the TOP;
- Following processes established for resolving data conflicts as specified in TOP-003-3, or other applicable Reliability Standards;
- Taking corrective actions on the TOP's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the TOP's Real-time Assessment; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the quality of the Real-time Assessment so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R2

The BA uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The BA's Operating Process or Operating Procedure must contain criteria for evaluating the quality of Real-time data as specified in proposed TOP-010-1 Requirement R2 Part 2.1. The criteria supports identification of applicable data quality issues, which may include:

- Data outside of a prescribed data range;
- Analog data not updated within a predetermined time period;
- Data entered manually to override telemetered information; or
- Data otherwise identified as invalid or suspect.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 specifies the BA shall include in its Operating Process or Operating Procedure actions to address Real-time data quality issues when data quality affects its analysis functions. Requirement R2 Part 2.3 is focused on addressing data point quality issues affecting analysis functions. Other data quality issues of a lower priority are addressed according to an entity's operating practices and are not covered under Requirement R2 Part 2.3.

The BA's actions to address data quality issues are steps within existing authorities and capabilities that provide awareness and enable the BA to meet its obligations for performing its analysis functions. Examples of actions to address data quality issues include, but are not limited to, the following:

- Notifying entities that provide Real-time data to the BA;

Supplemental Material

- Following processes established for resolving data conflicts as specified in TOP-003-3 or other applicable Reliability Standards;
- Taking corrective actions on the BA's own data;
- Changing data sources or other inputs so that the data quality issue no longer affects the BA's analysis functions; and
- Inputting data manually and updating as necessary.

The Operating Process or Operating Procedure must clearly identify to operating personnel how to determine the data that affects the analysis quality so that effective actions can be taken to address data quality issues in an appropriate timeframe.

Requirement R3

Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments may include, as applicable, state estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

Examples of the types of criteria used to evaluate the quality of analysis used in Real-time Assessments may include solution tolerances, mismatches with Real-time data, convergences, etc.

The Operating Process or Operating Procedure must describe how the quality of analysis results used in Real-time Assessment will be shown to operating personnel.

Requirement R4

Requirement R4 addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

An alarm process monitor could be an application within a Real-time monitoring system or it could be a separate system. 'Heartbeat' or 'watchdog' monitors are examples of an alarm process monitor. An alarm process monitor should be designed and implemented such that a stall of the Real-time monitoring alarm processor does not cause a failure of the alarm process monitor.

Rationale

Rationale for Requirement R1: The Transmission Operator (TOP) uses a set of Real-time data identified in TOP-003-3 Requirement R1 to perform its Real-time monitoring and Real-time Assessments. Functional requirements to perform Real-time monitoring and Real-time Assessments appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R1 Part 1.3 of this standard specifies the TOP shall include actions to address Real-time data quality issues affecting its Real-time Assessments in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process used to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2, provided that this process addresses Real-time data quality issues.

The revision in Part 1.3 to address Real-time data quality issues *when data quality affects Real-time Assessments* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R2: The Balancing Authority (BA) uses a set of Real-time data identified in TOP-003-3 Requirement R2 to perform its analysis functions and Real-time monitoring. Requirements to perform monitoring appear in other Reliability Standards.

The Operating Process or Operating Procedure must include provisions for indicating the quality of Real-time data to operating personnel. Descriptions of quality indicators such as display color codes, data quality flags, or other such indicators as found in Real-time monitoring specifications could be used.

Requirement R2 Part 2.3 of this standard specifies the BA shall include actions to address Real-time data quality issues affecting its analysis functions in its Operating Process or Operating Procedure. Examples of actions to address Real-time data quality issues are provided in the Guidelines and Technical Basis section. These actions could be the same as the process to resolve data conflicts required by TOP-003-3 Requirement R5 Part 5.2 provided that this process addresses Real-time data quality issues.

The revision in Part 2.3 to address Real-time data quality issues *when data quality affects its analysis functions* clarifies the scope of data points that must be covered by the Operating Process or Operating Procedure.

Rationale for Requirement R3: Requirement R3 ensures TOPs have procedures to address issues related to the quality of the analysis results used for Real-time Assessments. Requirements to perform Real-time Assessments appear in other Reliability Standards. Examples of the types of analysis used in Real-time Assessments include, as applicable, state

estimation, Real-time Contingency analysis, Stability analysis or other studies used for Real-time Assessments.

The Operating Process or Operating Procedure must include provisions for how the quality of analysis results used in Real-time Assessment will be shown to operating personnel. Operating personnel includes System Operators and staff responsible for supporting Real-time operations.

Rationale for Requirement R4: The requirement addresses recommendation S7 of the Real-time Best Practices Task Force report concerning operator awareness of alarm availability.

The requirement in Draft Two of the proposed standard has been revised for clarity by removing the term *independent*. The alarm process monitor must be able to provide notification of failure of the Real-time monitoring alarm processor. This capability could be provided by an application within a Real-time monitoring system or by a separate component used by the System Operator. The alarm process monitor must not fail with a simultaneous failure of the Real-time monitoring alarm processor.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TOP-010-1 — Real-time Reliability Monitoring and Analysis Capabilities

United States

Standard	Requirement	Enforcement Date	Inactive Date
TOP-010-1	All	04/01/2018	

Reliability Standard TPL-007-1

A. Introduction

- 1. Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events
- 2. Number:** TPL-007-1
- 3. Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1** Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
 - 4.1.2** Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
 - 4.1.3** Transmission Owner who owns a Facility or Facilities specified in 4.2;
 - 4.1.4** Generator Owner who owns a Facility or Facilities specified in 4.2.
 - 4.2. Facilities:**
 - 4.2.1** Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
- 5. Background:**

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 Misoperation(s), the combination of which may result in voltage collapse and blackout.
- 6. Effective Date:**

See Implementation Plan for TPL-007-1

B. Requirements and Measures

- R1.** Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s).
[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
- M1.** Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s),

in accordance with Requirement R1.

- R2.** Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s). *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- M2.** Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).
- R3.** Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M3.** Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.
- R4.** Each responsible entity, as determined in Requirement R1, shall complete a GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon once every 60 calendar months. This GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
 - 4.1.** The study or studies shall include the following conditions:
 - 4.1.1.** System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and
 - 4.1.2.** System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.
 - 4.2.** The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements in Table 1.
 - 4.3.** The GMD Vulnerability Assessment shall be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners, and to any functional entity that submits a written request and has a reliability-related need.
 - 4.3.1.** If a recipient of the GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

- M4.** Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its GMD Vulnerability Assessment within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.
- R5.** Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 5.1.** The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.
- 5.2.** The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.
- M5.** Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

- R6.** Each Transmission Owner and Generator Owner shall conduct a thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The thermal impact assessment shall: *[Violation Risk Factor: Medium]* *[Time Horizon: Long-term Planning]*
- 6.1.** Be based on the effective GIC flow information provided in Requirement R5;
 - 6.2.** Document assumptions used in the analysis;
 - 6.3.** Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and
 - 6.4.** Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.
- M6.** Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.
- R7.** Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that their System does not meet the performance requirements of Table 1 shall develop a Corrective Action Plan addressing how the performance requirements will be met. The Corrective Action Plan shall: *[Violation Risk Factor: High]* *[Time Horizon: Long-term Planning]*
- 7.1.** List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
 - Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
 - Installation, modification, or removal of Protection Systems or Special Protection Systems.
 - Use of Operating Procedures, specifying how long they will be needed as part of the Corrective Action Plan.
 - Use of Demand-Side Management, new technologies, or other initiatives.
 - 7.2.** Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.
 - 7.3.** Be provided within 90 calendar days of completion to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), functional entities referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need.

7.3.1. If a recipient of the Corrective Action Plan provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements of Table 1 shall have evidence such as electronic or hard copies of its Corrective Action Plan, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan or relevant information, if any, within 90 calendar days of its completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan, and any functional entity that submits a written request and has a reliability-related need, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its Corrective Action Plan within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Table 1 –Steady State Planning Events				
<p>Steady State:</p> <ul style="list-style-type: none"> a. Voltage collapse, Cascading and uncontrolled islanding shall not occur. b. Generation loss is acceptable as a consequence of the planning event. c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. 				
Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
<p>GMD GMD Event with Outages</p>	<p>1. System as may be postured in response to space weather information¹, and then 2. GMD event²</p>	<p>Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event</p>	<p>Yes³</p>	<p>Yes³</p>

Table 1 – Steady State Performance Footnotes
<ol style="list-style-type: none"> 1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. 2. The GMD conditions for the planning event are described in Attachment 1 (Benchmark GMD Event). 3. Load loss as a result of manual or automatic Load shedding (e.g. UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark GMD Event

The benchmark GMD event¹ defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshape to facilitate time-domain analysis of GMD impact on equipment.

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak} , can be obtained from the reference geoelectric field value of 8 V/km using the following relationship

$$E_{\text{peak}} = 8 \times \alpha \times \beta \text{ (V/km)} \quad (1)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure.

Scaling the Geomagnetic Field

The benchmark GMD event is defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115L)} \quad (2)$$

where L is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α ; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

¹ The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: <http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx>

Geomagnetic Latitude (Degrees)	Scaling Factor ¹ (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Goelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak goelectric field, E_{peak} , used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the goelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;² or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2) or Table 2, β is applied to the reference goelectric field using equation (1) to obtain the regional goelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment. When a ground conductivity model is not available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.³ The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta = E/8 \tag{3}$$

² Available at the NERC GMD Task Force project page: [http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-\(GMDTF\)-2013.aspx](http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx)

³ Available at <http://geomag.usgs.gov/conductivity/>

where E is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

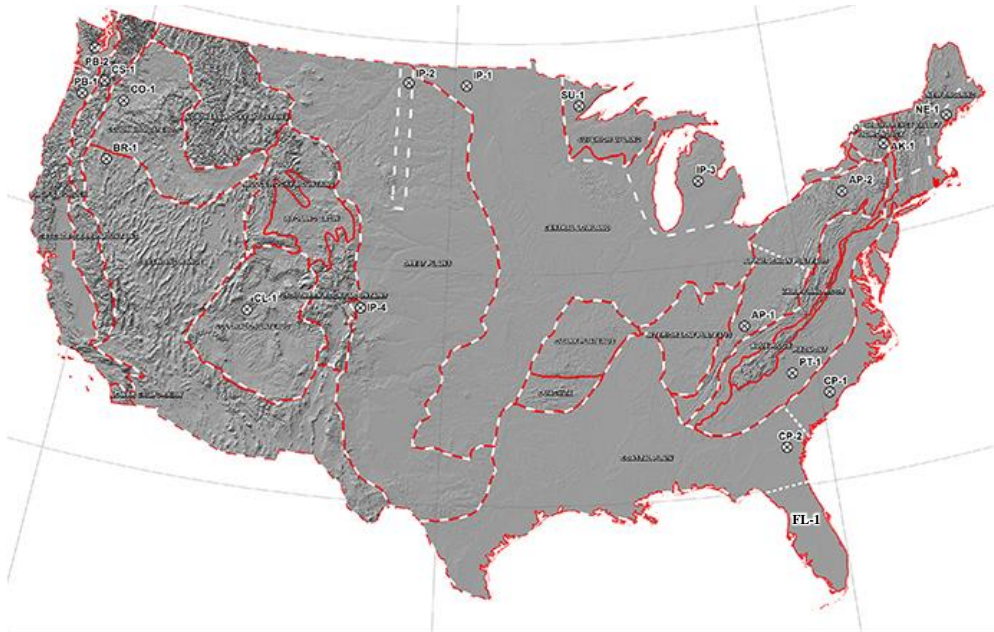


Figure 1: Physiographic Regions of the Continental United States⁴



Figure 2: Physiographic Regions of Canada

⁴ Additional map detail is available at the U.S. Geological Survey (<http://geomag.usgs.gov/>)

Table 3 – Geoelectric Field Scaling Factors	
USGS Earth model	Scaling Factor (β)
AK1A	0.56
AK1B	0.56
AP1	0.33
AP2	0.82
BR1	0.22
CL1	0.76
CO1	0.27
CP1	0.81
CP2	0.95
FL1	0.74
CS1	0.41
IP1	0.94
IP2	0.28
IP3	0.93
IP4	0.41
NE1	0.81
PB1	0.62
PB2	0.46
PT1	1.17
SL1	0.53
SU1	0.93
BOU	0.28
FBK	0.56
PRU	0.21
BC	0.67
PRAIRIES	0.96
SHIELD	1.0
ATLANTIC	0.79

Table 4 – Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveshape⁵

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveshape to be used to calculate the GIC time series, $GIC(t)$, required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55° ; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). Sampling rate for the geomagnetic field waveshape is 10 seconds.⁶ To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate conductivity scaling factor β .

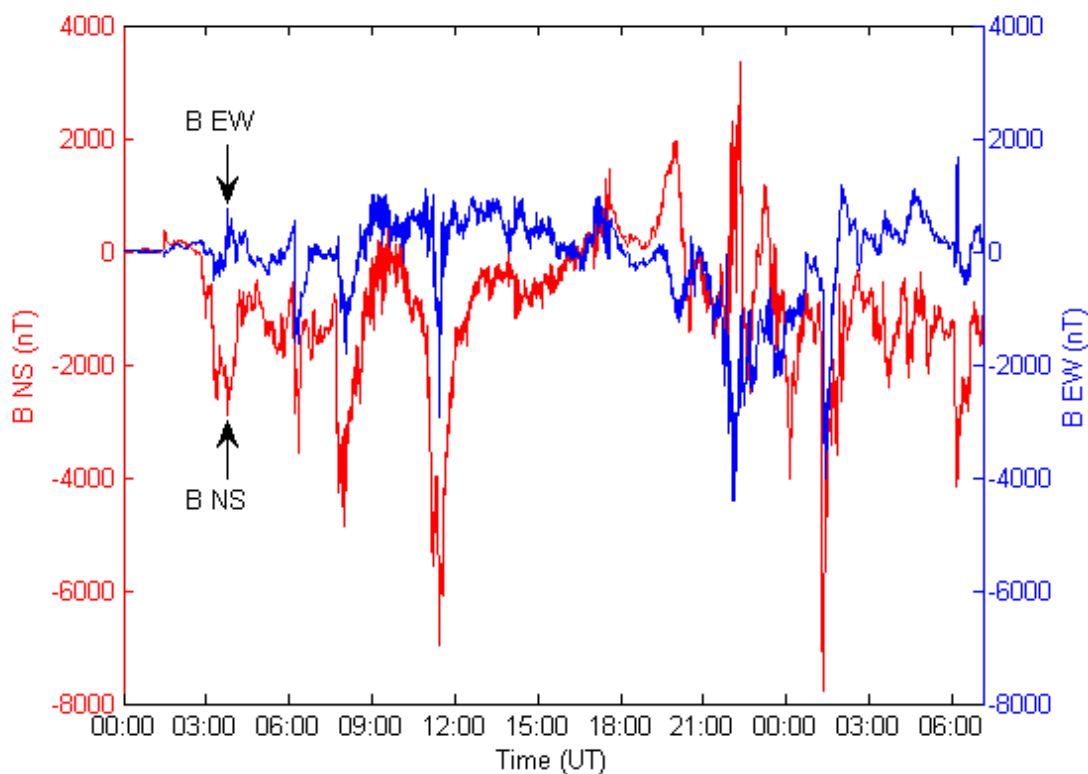


Figure 3: Benchmark Geomagnetic Field Waveshape. Red B_n (Northward), Blue B_e (Eastward)

⁵ Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: <http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx>

⁶ The data file of the benchmark geomagnetic field waveshape is available on the NERC GMD Task Force project page: [http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-\(GMDTF\)-2013.aspx](http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx)

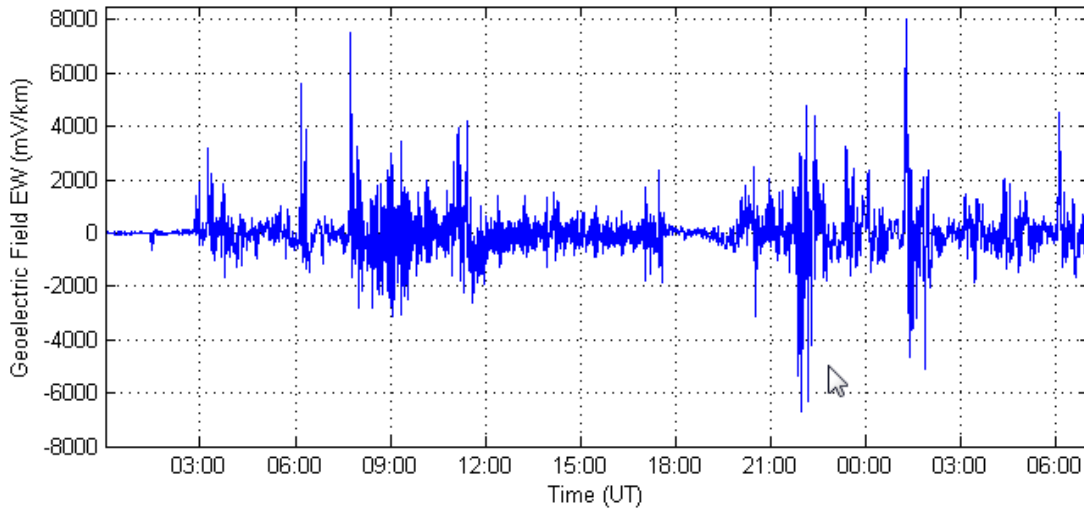


Figure 4: Benchmark Geoelectric Field Waveshape - E_E (Eastward)

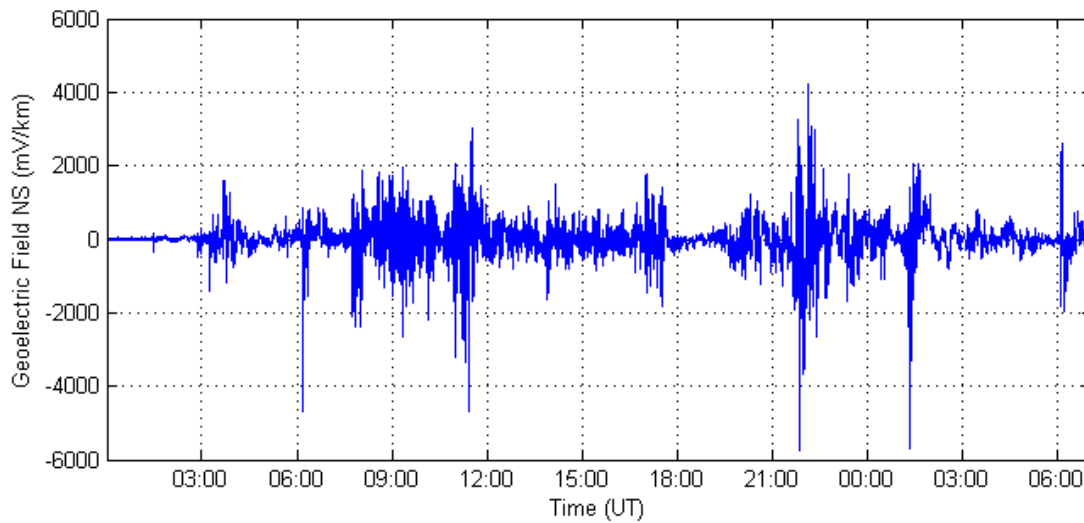


Figure 5: Benchmark Geoelectric Field Waveshape - E_N (Northward)

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 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 Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner shall 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 Requirements R1, R2, R3, R5, and R6, each responsible entity shall retain documentation as evidence for five years.

For Requirement R4, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.

For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.

If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner 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:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

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	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator’s planning area for maintaining models and performing the study or studies needed to complete GMD Vulnerability Assessment(s).
R2	Long-term Planning	High	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible	The responsible entity did not maintain both System models and GIC System models of the responsible

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					entity’s planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).	entity’s planning area for performing the study or studies needed to complete GMD Vulnerability Assessment(s).
R3	Long-term Planning	Medium	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event described in Attachment 1 as required.
R4	Long-term Planning	High	The responsible entity completed a GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last GMD Vulnerability Assessment.	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it	The responsible entity's completed GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a GMD Vulnerability Assessment, but it

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				was more than 64 calendar months and less than or equal to 68 calendar months since the last GMD Vulnerability Assessment.	was more than 68 calendar months and less than or equal to 72 calendar months since the last GMD Vulnerability Assessment.	was more than 72 calendar months since the last GMD Vulnerability Assessment; OR The responsible entity does not have a completed GMD Vulnerability Assessment.
R5	Long-term Planning	Medium	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.

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<p>R6</p>	<p>Long-term Planning</p>	<p>Medium</p>	<p>The responsible entity failed to conduct a thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than</p>	<p>The responsible entity failed to conduct a thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so</p>	<p>The responsible entity failed to conduct a thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so</p>	<p>The responsible entity failed to conduct a thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar</p>
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TPL-007-1 — Transmission System Planned Performance for Geomagnetic Disturbance Events

			<p>or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.</p>	<p>more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.</p>	<p>more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.</p>	<p>months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.</p>
R7	Long-term Planning	High	N/A	<p>The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.3.</p>	<p>The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.3.</p>	<p>The responsible entity's Corrective Action Plan failed to comply with all three of the elements in Requirement R7, Parts 7.1 through 7.3; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.</p>

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	

Application Guidelines

Guidelines and Technical Basis

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

<http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx>

Requirement R2

A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response.

Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*.

The guide is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%20202013/GIC%20Application%20Guide%202013_approved.pdf

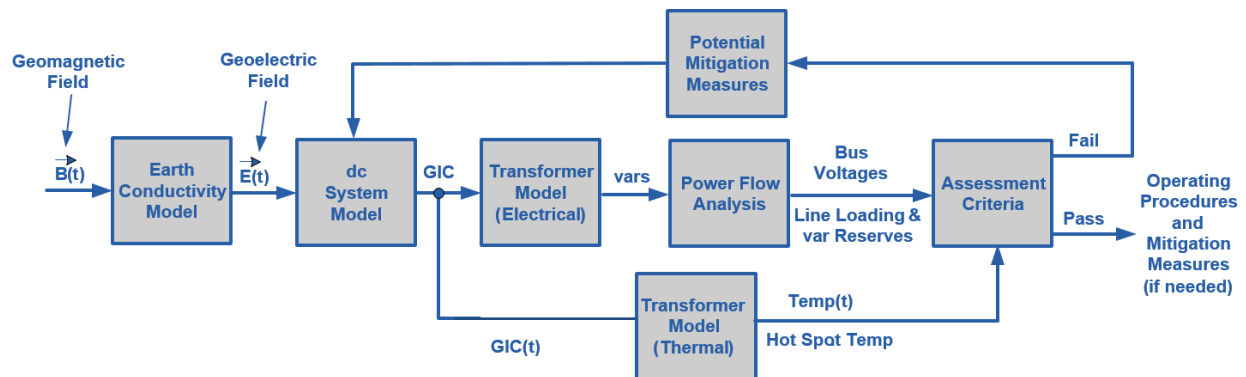
Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%20202013/GMD%20Planning%20Guide_approved.pdf

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



Application Guidelines

Requirement R5

The transformer thermal impact assessment specified in Requirement R6 is based on GIC information for the Benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper posted on the project page.

<http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx>

Transformers are exempt from the thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The threshold criteria and transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*:

<http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf>

Application Guidelines

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 Applicability:

Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:

In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:

A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

Rationale for R3:

Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

Application Guidelines

Rationale for R4:

The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R5:

This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

<http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx>

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase. Only those transformers that experience an effective GIC value of 75 A per phase

Application Guidelines

or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

<http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx>

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R7:

Corrective Action Plans are defined in the NERC Glossary of Terms:

A list of actions and an associated timetable for implementation to remedy a specific problem.

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the Benchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force *GMD Planning Guide* provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7, Part 7.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for Table 3:

Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard TPL-007-1 — Transmission System Planned Performance for Geomagnetic Disturbance Events

United States

Standard	Requirement	Enforcement Date	Inactive Date
TPL-007-1	R1.	07/01/2017	
TPL-007-1	R2.	07/01/2018	
TPL-007-1	R3.	01/01/2022	
TPL-007-1	R4.	01/01/2022	
TPL-007-1	4.1.	01/01/2022	
TPL-007-1	4.1.1.	01/01/2022	
TPL-007-1	4.1.2.	01/01/2022	
TPL-007-1	4.2.	01/01/2022	
TPL-007-1	4.3.	01/01/2022	
TPL-007-1	4.3.1.	01/01/2022	
TPL-007-1	R5.	01/01/2019	
TPL-007-1	5.1.	01/01/2019	
TPL-007-1	5.2.	01/01/2019	
TPL-007-1	R6.	01/01/2021	
TPL-007-1	6.1.	01/01/2021	
TPL-007-1	6.2.	01/01/2021	
TPL-007-1	6.3.	01/01/2021	
TPL-007-1	6.4.	01/01/2021	
TPL-007-1	R7.	01/01/2022	
TPL-007-1	7.1.	01/01/2022	
TPL-007-1	7.2.	01/01/2022	
TPL-007-1	7.3.	01/01/2022	
TPL-007-1	7.3.1.	01/01/2022	

Exhibit B

List of Currently Effective NERC Reliability Standards in Third Quarter 2016

Exhibit B: List of Currently Effective NERC Reliability Standards in Third Quarter 2016

Resource and Demand Balancing (BAL)

BAL-001-2	Real Power Balancing Control Performance
BAL-001-TRE-1	Primary Frequency Response in the ERCOT Region
BAL-002-1	Disturbance Control Performance
BAL-002-WECC-2	Contingency Reserve
BAL-003-1.1	Frequency Response and Frequency Bias Setting
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

Communications (COM)

COM-001-2.1	Communications
COM-002-4	Operating Personnel Communications Protocols

Critical Infrastructure Protection (CIP)

CIP-002-5.1	Cyber Security — BES Cyber System Categorization
CIP-003-6	Cyber Security — Security Management Controls
CIP-004-6	Cyber Security — Personnel & Training
CIP-005-5	Cyber Security — Electronic Security Perimeter(s)
CIP-006-6	Cyber Security — Physical Security of BES Cyber Systems
CIP-007-6	Cyber Security — System Security Management
CIP-008-5	Cyber Security — Incident Reporting and Response Planning
CIP-009-6	Cyber Security — Recovery Plans for BES Cyber Systems
CIP-010-2	Cyber Security — Configuration Change Management and Vulnerability Assessments
CIP-011-2	Cyber Security — Information Protection
CIP-014-2	Physical Security

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
EOP-010-1	Geomagnetic Disturbance Operations

Facilities Design, Connections, and Maintenance (FAC)

FAC-001-2	Facility Interconnection Requirements
FAC-002-2	Facility Interconnection Studies
FAC-003-4	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-004-3.1	Dynamic Transfers
INT-006-4	Evaluation of Interchange Transactions
INT-009-2.1	Implementation of Interchange
INT-010-2.1	Interchange Initiation and Modification for Reliability

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-2	Transmission Loading Relief Procedure for the Eastern Interconnection
IRO-006-TRE-1	IROL and SOL Mitigation in the ERCOT Region
IRO-006-WECC-2	Qualified Transfer Path Unscheduled Flow (USF) Relief
IRO-008-1	Reliability Coordinator Operational Analyses and Real-time Assessments
IRO-009-2	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-020-0	Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators
MOD-025-2	Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
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
MOD-031-2	Demand and Energy Data
MOD-032-1	Data for Power System Modeling and Analysis

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NUC-001-3	Nuclear Plant Interface Coordination
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PER-003-1	Operating Personnel Credentials
PER-004-2	Reliability Coordination — Staffing
PER-005-2	Operations Personnel Training

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PRC-002-2	Disturbance Monitoring and Reporting Requirements
PRC-004-4(i)	Protection System Misoperation Identification and Correction

PRC-004-WECC-1	Protection System and Remedial Action Scheme Misoperation
PRC-005-1.1b	Transmission and Generation Protection System Maintenance and Testing
PRC-005-2(i)	Protection System Maintenance
PRC-005-6	Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
PRC-006-2	Automatic Underfrequency Load Shedding
PRC-006-NPCC-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-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
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PRC-022-1	Under-Voltage Load Shedding Program Performance
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TOP-002-2.1b	Normal Operations Planning
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TPL-001-4 [Transmission System Planning Performance Requirements](#)

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VAR-001-4.1 [Voltage and Reactive Control](#)

VAR-002-4 [Generator Operation for Maintaining Network Voltage Schedules](#)

VAR-002-WECC-2 [Automatic Voltage Regulators \(AVR\)](#)

VAR-501-WECC-2 [Power System Stabilizer \(PSS\)](#)

Exhibit C: Updated *Glossary of Terms Used in NERC Reliability Standards*

Glossary of Terms Used in NERC Reliability Standards

Updated September 29, 2016

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 September 29, 2016.

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 RF 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.
- Definitions that have been approved by FERC are white.

Any comments regarding this glossary should be reported to the following:

sarcomm@nerc.com with "Glossary Comment" in the subject line.

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Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
Actual Frequency (F_A) [Archive]		2/11/2016	6/23/2016 (Becomes effective 7/1/2016)	The Interconnection frequency measured in Hertz (Hz).
Actual Net Interchange (NI_A) [Archive]		2/11/2016	6/23/2016 (Becomes effective 7/1/2016)	The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.
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.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
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.
Alternative Interpersonal Communication [Archive]		11/7/2012	4/16/2015 (Becomes effective 10/1/2015)	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. <i>(From FERC order 888-A.)</i>
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.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
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.
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.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
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.
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.
Automatic Generation Control [Archive]	AGC	2/11/2016		A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
<p>Automatic Time Error Correction (I_{ATEC})</p> <p>[Archive]</p>		2/11/2016	6/23/2016 (Becomes effective 7/1/2016)	<p>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.</p> $I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$ <p>when operating in Automatic Time Error Correction Mode.</p> <p>The absolute value of I_{ATEC} shall not exceed L_{max}.</p> <p>I_{ATEC} shall be zero when operating in any other AGC mode.</p> <ul style="list-style-type: none"> L_{max} is the maximum value allowed for I_{ATEC} set by each BA between $0.2* B_i$ and L_{10}, $0.2* B_i \leq L_{max} \leq L_{10}$. $L_{10} = 1.65 * \epsilon_{10} \sqrt{(-10B_i)(-10B_S)}$. ϵ_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ϵ_{10}, is the same for every Balancing Authority Area within an Interconnection. $Y = B_i / B_S$. H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3. <i>(Continued below)</i>

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
<p>Automatic Time Error Correction (I_{ATEC})</p> <p><i>Continued...</i></p> <p>[Archive]</p>		2/11/2016	6/23/2016 (Becomes effective 7/1/2016)	<ul style="list-style-type: none"> • B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz). • B_s = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz). • Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$ • 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required, where: $PII_{accum}^{on/offpeak} = last\ period's\ PII_{accum}^{on/offpeak} + PII_{hourly}$

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
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.
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.

Continent-wide Term	Acronym	BOT Approval Date	FERC Approval Date	Definition
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 [Archive]		2/11/2016		The responsible entity that integrates resource plans ahead of time, maintains Demand and resource 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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Balancing Contingency Event [Archive]		11/5/2015		Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less. A. Sudden loss of generation: a. Due to i. unit tripping, or ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or iii. sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
BES Cyber Asset [Archive]		11/26/2012	11/22/2013 (Becomes inactive 6/30/2016)	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required 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.)
BES Cyber Asset [Archive]	BCA	2/12/2015	1/21/2016 (effective 7/1/2016)	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.
BES Cyber System [Archive]		11/26/2012	11/22/2013 (Becomes effective 7/1/2016)	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
BES Cyber System Information [Archive]		11/26/2012	11/22/2013 (Becomes effective 7/1/2016)	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.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Blackstart Resource [Archive]		8/5/2009	3/17/2011	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.
Blackstart Resource [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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	6/14/2013 (Replaced by BES definition FERC approved 3/20/2014)	<p>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.</p> <p>Inclusions:</p> <ul style="list-style-type: none"> • 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			<p>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.</p> <p>Exclusions:</p> <ul style="list-style-type: none"> • E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: <ul style="list-style-type: none"> 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). <p>Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Bulk Electric System (Continued)	BES			<ul style="list-style-type: none"> • 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			<p>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);</p> <p>b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and</p> <p>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).</p> <ul style="list-style-type: none"> • 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 Implementation 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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> 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			<ul style="list-style-type: none"> 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. <ul style="list-style-type: none"> • 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. <p>Exclusions:</p> <ul style="list-style-type: none"> • E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: <ul style="list-style-type: none"> 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			<p>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.</p> <p>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.</p> <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> 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			<p>generation greater than 75 MVA (gross nameplate rating);</p> <p>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</p> <p>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).</p> <ul style="list-style-type: none"> • E4 – Reactive Power devices installed for the sole benefit of a retail customer(s). <p>Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.</p>
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
Bulk-Power System [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	Bulk-Power System: (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. (Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.)
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 11/24/2009	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 1/1/2015)	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 [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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.
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	11/22/2013 (Becomes effective 7/1/2016)	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	11/22/2013 (Becomes effective 7/1/2016)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Compliance Monitor [Archive]		2/8/2005	3/16/2007	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
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.
Composite Protection System [Archive]		8/14/2014	5/13/2015 (Becomes effective 7/1/2016)	The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.
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 1/1/2015)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
Contingency Event Recovery Period [Archive]		11/5/2015		A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Contingency Reserve [Archive]		11/5/2015		The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority: <ul style="list-style-type: none"> • is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan. • is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
Contingency Reserve Restoration Period [Archive]		11/5/2015		A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Control Center [Archive]		11/26/12	11/22/13 (Becomes effective 7/1/2016)	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.
Critical Assets [Archive]		5/2/2006	1/18/2008 (Becomes inactive 3/31/2016)	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 3/31/2016)	Cyber Assets essential to the reliable operation of Critical Assets.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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 6/30/2016)	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Assets [Archive]		11/26/12	11/22/2013 (Becomes effective 7/1/2016)	Programmable electronic devices, including the hardware, software, and data in those devices.
Cyber Security Incident [Archive]		5/2/2006	1/18/2008 (Becomes inactive 6/30/2016)	Any malicious act or suspicious event that: <ul style="list-style-type: none"> • 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 7/1/2016)	A malicious act or suspicious event that: <ul style="list-style-type: none"> • 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	<ol style="list-style-type: none"> 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	2/19/2015 (Becomes effective 7/1/2016)	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 7/1/2016)	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.
Distribution Provider [Archive]	DP	11/5/2015	1/21/2016 (effective 7/1/2016)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Disturbance [Archive]		2/8/2005	3/16/2007	<ol style="list-style-type: none"> 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.
Disturbance Monitoring Equipment [Archive]	DME	8/2/2006	3/16/2007	<p>Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders³:</p> <ul style="list-style-type: none"> • 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

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 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).
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 7/1/2016)	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 7/1/2016)	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 kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh).
Electronic Security Perimeter [Archive]	ESP	5/2/2006	1/18/2008 (Becomes inactive 6/30/2016)	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 7/1/2016)	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.
Element [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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.
Energy Emergency [Archive]		11/13/2014	11/19/2015 effective 4/1/2017	A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
External Routable Connectivity [Archive]		11/26/12	11/22/2013 (Becomes effective 7/1/2016)	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	<p>1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.</p> <p>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.</p>
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	<p>1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons.</p> <p>2. The condition in which the equipment is unavailable due to unanticipated failure.</p>
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 3/31/2015)	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 4/1/2015)	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 4/1/2015)	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 4/1/2015)	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 4/1/2015)	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 Operator [Archive]	GOP	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity that operates generating Facility(ies) 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 Owner [Archive]	GO	11/5/2015	1/21/2016 (effective 7/1/2016)	Entity that owns and maintains generating Facility(ies).
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment [Archive]	GMD	12/17/2014	09/22/2016 (effective 7/1/2017)	Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.
Host Balancing Authority [Archive]		2/8/2005	3/16/2007	<ol style="list-style-type: none"> 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 7/1/2016)	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 Authority [Archive]	IA	11/5/2015	1/21/2016 (effective 7/1/2016)	The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
Interchange Meter Error (I_{ME}) [Archive]		2/11/2016	6/23/2016 (Becomes effective 7/1/2016)	A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Interconnected Operations Service [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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 (Retires 6/30/2016)	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection [Archive]		8/15/2013	4/16/2015	When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Interconnection [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
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.

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
Intermediate System [Archive]		11/26/12	11/22/2013 (Becomes effective 7/1/2016)	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.
Interpersonal Communication [Archive]		11/7/2012	4/16/2015 (Becomes effective 10/1/2015)	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.
Load-Serving Entity [Archive]	LSE	11/5/2015	1/21/2016 (effective 7/1/2016)	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 1/1/2015)	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.
Low Impact BES Cyber System Electronic Access Point [Archive]	LEAP	2/12/2015	1/21/2016 (effective 7/1/2016)	A Cyber Asset interface that controls Low Impact External Routable Connectivity. The Cyber Asset containing the LEAP may reside at a location external to the asset or assets containing low impact BES Cyber Systems.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Low Impact External Routable Connectivity [Archive]	LERC	2/12/2015	1/21/2016 (effective 7/1/2016)	Direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection. Point-to-point communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between Transmission station or substation assets containing low impact BES Cyber Systems are excluded from this definition (examples of this communication include, but are not limited to, IEC 61850 GOOSE or vendor proprietary protocols).
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	<ul style="list-style-type: none"> 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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Misoperation [Archive]		8/14/2014	5/13/2015 (Becomes effective 7/1/2016)	<p>The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:</p> <ol style="list-style-type: none"> 1. Failure to Trip – During Fault – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct. 2. Failure to Trip – Other Than Fault – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct. 3. Slow Trip – During Fault – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. <p><i>(continued below)</i></p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
<p><i>Continued...</i> Misoperation [Archive]</p>		8/14/2014	5/13/2015 (Becomes effective 7/1/2016)	<p>4. Slow Trip – Other Than Fault – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System.</p> <p>5. Unnecessary Trip – During Fault – An unnecessary Composite Protection System operation for a Fault condition on another Element.</p> <p>6. Unnecessary Trip – Other Than Fault – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.</p>
<p>Most Severe Single Contingency [Archive]</p>	MSSC	11/5/2015		<p>The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority’s area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Native Balancing Authority [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.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
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	<ol style="list-style-type: none"> 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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
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	4/16/2015 (Becomes effective 7/1/2016)	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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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 (Becomes inactive 9/30/2014)	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, 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.).
Operational Planning Analysis [Archive]		11/13/2014	11/19/2015 (Becomes effective 1/1/2017)	An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Operational Planning Analysis [Archive]	OPA	8/11/2016		An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts; generation output levels; Interchange; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
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	<ol style="list-style-type: none"> 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 7/1/2016)	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 6/30/2016)	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 7/1/2016)	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 Authority [Archive]	PA	11/5/2015	1/21/2016 (effective 7/1/2016)	The responsible entity that coordinates and integrates transmission Facilities 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 of Receipt [Archive]	POR	11/5/2015	1/21/2016 (effective 7/1/2016)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
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
Pre-Reporting Contingency Event ACE Value [Archive]		11/5/2015		The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protected Cyber Assets [Archive]	PCA	11/26/2012	11/22/2013 (Becomes effective 6/30/2016)	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.
Protected Cyber Assets [Archive]	PCA	2/12/2015	1/21/2016 (effective 7/1/2016)	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.
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 – <ul style="list-style-type: none"> • 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 station 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.
Protection System Coordination Study [Archive]		11/5/2015		An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program (PRC-005-2) [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 (PRC-005-3) [Archive]	PSMP	11/7/2013	1/22/2015 (Becomes effective 4/1/2016)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Protection System Maintenance Program (PRC-005-4) [Archive]	PSMP	11/13/2014	9/17/2015 (Becomes effective 1/1/2016)	An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying 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: <ul style="list-style-type: none"> • 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 (PRC-005-6) [Archive]	PSMP	11/5/2015	12/18/2015 (Becomes effective 1/1/2016)	<p>An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying 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:</p> <ul style="list-style-type: none"> • 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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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).
Pseudo-Tie [Archive]		2/11/2016		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' Reporting ACE equation (or alternate control processes).
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
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).
Reactive Power [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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).

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Real Power [Archive]		2/8/2005	3/16/2007	The portion of electricity that supplies energy to the load.
Real Power [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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
Real-time Assessment [Archive]		11/13/2014	Revised definition. 11/19/2015 (Becomes effective 1/1/2017)	An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Real-time Assessment [Archive]	RTA	8/11/2016		An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load; generation output levels; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Interchange; Facility Ratings; and identified phase angle and equipment limitations. (Realtime Assessment may be provided through internal systems or through third-party services.)
Receiving Balancing Authority [Archive]		2/8/2005	3/16/2007	The Balancing Authority importing the Interchange.
Regional Reliability Organization [Archive]	RRO	2/8/2005	3/16/2007	<ol style="list-style-type: none"> 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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Regulation Reserve Sharing Group [Archive]		8/15/2013	4/16/2015 (Becomes effective 7/1/2016)	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.
Reliability Adjustment RFI [Archive]		10/29/2008	12/17/2009	Request to modify an Implemented Interchange Schedule for reliability purposes.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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 [Archive]	RC	11/5/2015	1/21/2016 (effective 7/1/2016)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Directive [Archive]		8/16/2012	11/19/2015 (Becomes inactive 11/19/2015)	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.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reliability Standard [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	A requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk-Power System. The term includes requirements for the operation of existing 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 of the 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.
Reliable Operation [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	Operating the elements of the [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
Remedial Action Scheme [Archive]	RAS	11/13/2014	11/19/2015 effective 4/1/2017	<p>A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:</p> <ul style="list-style-type: none"> • Meet requirements identified in the NERC Reliability Standards; • Maintain Bulk Electric System (BES) stability; • Maintain acceptable BES voltages; • Maintain acceptable BES power flows; • Limit the impact of Cascading or extreme events. <p>The following do not individually constitute a RAS:</p> <ol style="list-style-type: none"> a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays c. Out-of-step tripping and power swing blocking d. Automatic reclosing schemes e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
<p>Continued Remedial Action Scheme [Archive]</p>				<ul style="list-style-type: none"> f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage) k. Automatic sequences that proceed when manually initiated solely by a System Operator l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
<i>Continued</i> Remedial Action Scheme [Archive]				n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing
Removable Media [Archive]		2/12/2015	1/21/2016 (effective 7/1/2016)	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reportable Balancing Contingency Event [Archive]		11/5/2015		Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity. <ul style="list-style-type: none"> • Eastern Interconnection – 900 MW • Western Interconnection – 500 MW • ERCOT – 800 MW • Quebec – 500 MW
Reportable Cyber Security Incident [Archive]		11/26/2012	11/22/2013 (Becomes effective 7/1/16)	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	4/16/2015 (Will not go into effect)	<p>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).</p> <p>Reporting ACE is calculated as follows:</p> $\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$ <p>Reporting ACE is calculated in the Western Interconnection as follows:</p> $\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}$ <p>Where:</p> <p>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.</p> <p>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</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE (Continued)				<p>Interchange Actual.</p> <p>B (Frequency Bias Setting) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.</p> <p>10 is the constant factor that converts the frequency bias setting units to MW/Hz.</p> <p>F_A (Actual Frequency) is the measured frequency in Hz.</p> <p>F_S (Scheduled Frequency) is 60.0 Hz, except during a time correction.</p> <p>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).</p> <p>I_{A TEC} (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.</p> $I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)^*H}$ <p>when operating in Automatic Time Error Correction control mode.</p> <p>I_{A TEC} shall be zero when operating in any other AGC mode.</p> <ul style="list-style-type: none"> • 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)				<ul style="list-style-type: none"> Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B * \Delta TE/6)$ 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. <p>Where:</p> $PII_{accum}^{on/off\ peak} = \text{last period's } PII_{accum}^{on/off\ peak} + PII_{hourly}$ <p>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</p>

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE (Continued)				<p>consistent with the measures included in this standard.</p> <ol style="list-style-type: none"> 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.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reporting ACE [Archive]		2/11/2016	6/23/2016 (Becomes effective 7/1/2016)	<p>The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).</p> <p>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: $\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}$ </p> <p>Where:</p> <ul style="list-style-type: none"> • NI_A = Actual Net Interchange. • NI_S = Scheduled Net Interchange. • B = Frequency Bias Setting. • F_A = Actual Frequency. • F_S = Scheduled Frequency. • I_{ME} = Interchange Meter Error. • I_{ATEC} = Automatic Time Error Correction.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
				<p>All NERC Interconnections 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:</p> <ol style="list-style-type: none"> 1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss; 2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times; 3. The use of a common Scheduled Frequency F_s for all BAAs at all times; and, 4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects 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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
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 [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Reserve Sharing Group Reporting ACE [Archive]		8/15/2013	4/16/2015	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.
Reserve Sharing Group Reporting ACE [Archive]		11/5/2015	(Becomes effective 7/1/2016)	At any given time of measurement for the applicable Reserve Sharing Group (RSG), the algebraic sum of the ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the RSG 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.
Resource Planner [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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.
Scheduled Net Interchange (NI _s) [Archive]		2/11/2016	6/23/2016 (Becomes effective 7/1/2016)	The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.
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.)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
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 (Becomes inactive 3/31/2017)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
Special Protection System (Remedial Action Scheme) [Archive]	SPS	5/5/2016	6/23/2016 (Becomes effective 4/1/2017)	See "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.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
System Operating Limit [Archive]	SOL	2/8/2005	3/16/2007	<p>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:</p> <ul style="list-style-type: none"> • 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)

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
System Operating Limit [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	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: <ul style="list-style-type: none"> • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings 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.
Telemetry [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	2/19/2015 (Becomes effective 7/1/2016)	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 <i>in a reliable manner</i> 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 <i>not</i> 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.
Transient Cyber Asset [Archive]		2/12/2015	1/21/2016 (effective 7/1/2016)	A Cyber Asset that (i) is capable of transmitting or transferring executable code, (ii) is not included in a BES Cyber System, (iii) is not a Protected Cyber Asset (PCA), and (iv) is directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless, including near field or Bluetooth communication) for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a PCA. Examples include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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	<ol style="list-style-type: none"> 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.
Transmission Customer [Archive]		11/5/2015	1/21/2016 (effective 7/1/2016)	<ol style="list-style-type: none"> 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 entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
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 [Archive]	TOP	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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 Owner [Archive]	TO	11/5/2015	1/21/2016 (effective 7/1/2016)	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 Planner [Archive]	TP	11/5/2015	1/21/2016 (effective 7/1/2016)	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.
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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
Transmission Service Provider [Archive]	TSP	11/5/2015	1/21/2016 (effective 7/1/2016)	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.
Undervoltage Load Shedding Program [Archive]	UVLS Program	11/13/2014	11/19/2015 effective 4/1/2017	An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.
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 (Becomes inactive 3/20/2013)	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.

Continent-wide Term	Acronym	BOT Approved Date	FERC Approved Date	Definition
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.
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: <ul style="list-style-type: none"> 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.

ReliabilityFirst Regional Definitions

The following definitions were developed for use in ReliabilityFirst 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 3/31/2014)	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 3/31/2014)	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: <i>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).</i>
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: <ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • 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. <ul style="list-style-type: none"> • Each RAS may have different components and operating characteristics.
Generating Unit Capability ¹ [Archive]		3/12/2007	6/8/2007	Means the MVA nameplate rating of a generator.
Non-spinning Reserve ¹ [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 ¹ [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 ¹ [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 ¹ [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.

[‡] 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.

Change History

Date	Action
September 28, 2016	Updated CIP v 5 standards effective date from 4/1/2016 to 7/1/2016 per FERC Order 822.
August 17, 2016	Board Adopted: Operational Planning Analysis and Real-time Assessment
July 13, 2016	Updated color coding of terms retired 6/30/2016 based on the terms becoming effective 7/1/2016.
June 24, 2016	<p>FERC approved: Actual Frequency, Actual Net Interchange, Scheduled Net Interchange (NIS), Interchange Meter Error (IME), and Automatic Time Error Correction (ATEC)</p> <p>Reporting ACE: status updated</p>
June 21, 2016	Correction: Reserve Sharing Group Reporting ACE, and Contingency Reserve changed to 11/5/2015 Board adoption date status
May 5, 2016	Board Adopted: Special Protection System (SPS)
April 1, 2016	Effective: BES Cyber Asset, BES Cyber System, BES Cyber System Information, CIP Exceptional Circumstance, CIP Senior Manager, Cyber Assets, Cyber Security Incident, Dial-up Connectivity, Electronic Access Control or Monitoring Systems, Electronic Access Point, Electronic Security Perimeter, External Routable Connectivity, Interactive Remote Access, Intermediate System, Physical Access Control Systems, Physical Security Perimeter
March 31, 2016	Inactive: Critical Assets, Critical Cyber Assets, Cyber Assets, Cyber Security Incident, Electronic Security Perimeter, Physical Security Perimeter