







## **I. NOTICE AND COMMUNICATIONS**

Notices and communications regarding this application may be addressed to:

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## **II. REQUEST FOR APPROVAL OF RELIABILITY STANDARD**

### **A. Background: NERC Quarterly Filing of Proposed Reliability Standards**

Pursuant to Section 215 of the Federal Power Act (“FPA”),<sup>2</sup> NERC was certified by FERC as the Electric Reliability Organization (“ERO”) in the United States.<sup>3</sup> Under FPA Section 215, the ERO is charged with developing and enforcing mandatory Reliability Standards in the United States, subject to FERC approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to FERC-approved Reliability Standards. Section 215(d)(5) of the FPA authorizes FERC to order the ERO to submit a new or modified Reliability Standard and Section 39.5(a) of FERC’s regulations requires the ERO to file for FERC approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to make effective in the United States. Some or all of NERC’s Reliability Standards are also mandatory in the Canadian provinces of Alberta,

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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 NSUAR in the present quarterly application and all previous applications should be considered for purposes of this application.

<sup>2</sup> 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).

<sup>3</sup> *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).

British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Québec, and Saskatchewan.

NERC entered into a Memorandum of Understanding (“MOU”) with the NSUARB,<sup>4</sup> and a separate MOU with Nova Scotia Power Incorporated (“NSPI”) and the Northeast Power Coordinating Council, Inc. (“NPCC”),<sup>5</sup> 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. On July 20, 2011, NSUARB issued a decision approving standards and NERC Glossary.<sup>6</sup> In that decision, the NSUARB approved a “quarterly review” process for considering new and amended NERC Reliability Standards and criteria<sup>7</sup> and ordered that “applications will not be processed by the Board until [FERC] has approved or remanded the standards in the United States.”<sup>8</sup> 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

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

<sup>5</sup> 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).

<sup>6</sup> *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”).

<sup>7</sup> *Id.* at P 30.

<sup>8</sup> *Id.*

and VSLs as guidance.<sup>9</sup>

Based on the NSUARB Decision, NERC applications to the NSUARB only request approval for those Reliability Standards and *NERC 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 to the FERC-approved VRFs and VSLs associated with NERC Reliability Standards.<sup>10</sup> 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 a balloting process, approve the Reliability Standards prior to the standards being adopted by the NERC Board of Trustees and approved by applicable governmental authorities.

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<sup>9</sup> *Id.* at P 33.

<sup>10</sup> 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.

NERC develops Reliability Standards and associated definitions in accordance with Section 300 (Reliability Standards Development) and Appendix 3A (Standards Processes Manual) of its Rules of Procedure.<sup>11</sup> 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 July 3, 2018, 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.

**C. Description of Proposed Reliability Standard, Third Quarter 2018**

As provided in the table below, during the third quarter of 2018, FERC issued a delegated order approving Reliability Standard BAL-002-3.<sup>12</sup> No other Reliability Standards or definitions were approved during the third quarter of 2018.

Reliability Standard	Effective Date
Resource and Demand Balancing (BAL) Standard	
BAL-002-3*	4/1/2019

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

*1. BAL-002-3*

On September 25, 2018, FERC approved Reliability Standard BAL-002-3 (Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event) and the retirement of currently-effective Reliability Standard BAL002-2. Reliability Standard BAL-002-3 is designed to ensure that the Balancing Authority [(“BA”)] or Reserve Sharing Group [(“RSG”)] balances resources and demand and returns the [BA]’s or [RSG]’s Area Control Error [(“ACE”)] to defined values (subject to applicable limits) following a Reportable

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

<sup>12</sup> *N. Am. Elec. Reliability Corp.*, Docket No. RD18-7-000 (Sept. 25, 2018) (unpublished letter order).

Balancing Contingency Event. To support this goal, Requirement R1 mandates certain actions upon a Reportable Balancing Contingency Event to (i) return Reporting ACE to defined values within the Contingency Event Recovery Period; (ii) document Reportable Balancing Contingency Events; and (iii) deploy Contingency Reserves. Within this rubric, Requirement R1 Part 1.3 provides a limited exemption from the BA's or RSG's obligation to restore Reporting ACE within the Contingency Event Recovery Period if the entity is recovering from an emergency event under NERC Emergency Preparedness and Operations Reliability Standards and meets certain other qualifications.

NERC submitted BAL-002-3 to address FERC's directives in Order No. 835 to develop modifications to the currently effective Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities or Reserve Sharing Groups to: (1) notify the Reliability Coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) provide the Reliability Coordinator with its ACE recovery plan, including a target recovery time.<sup>13</sup>

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<sup>13</sup> *Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard*, Order No. 835, 158 FERC ¶ 61,030, at P 37 (2017).

**III. CONCLUSION**

NERC respectfully requests that the NSUARB approve the Reliability Standard as specified herein.

Respectfully submitted,

*/s/ Shamai Elstein*

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Date: November 30, 2018

**Exhibit A (1): Reliability Standard Applicable to Nova Scotia, Approved by  
FERC in Third Quarter 2018**

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Third Quarter 2018**

<b>Reliability Standard</b>	<b>Effective Date</b>
Resource and Demand Balancing (BAL) Standard	
BAL-002-3*	4/1/2019

\* At the time of this filing, all standards and definitions 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 Reliability Standard  
Applicable to Nova Scotia, Approved by FERC in Third Quarter 2018**

**Exhibit A (2): Informational Summary of Reliability Standard Applicable to Nova Scotia, Approved by FERC in Third Quarter 2018**

<b>Reliability Standard BAL-002-3</b>	
<b>Purpose</b>	To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
<b>Applicability</b>	<ul style="list-style-type: none"> <li>• Balancing Authorities               <ul style="list-style-type: none"> <li>○ A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.</li> </ul> </li> <li>• Reserve Sharing Group</li> </ul>
<b>Requirements</b>	Reliability Standard BAL-002-3 includes three requirements.
<b>Date of Petition and FERC Order</b>	Petition filed on August 17, 2018 for approval of proposed Reliability Standard BAL-002-3 with the Federal Energy Regulatory Commission (“FERC”) in Docket No. RM18-7-000. FERC approved the BAL standard on September 25, 2018.

**Exhibit A (3): Reliability Standard Filed for Approval**

## **Reliability Standard BAL-002-3**

## **A. Introduction**

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-3
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**
  - 4.1. **Responsible Entity**
    - 4.1.1. **Balancing Authority**
      - 4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.
    - 4.1.2. **Reserve Sharing Group**
5. **Effective Date:** See the Implementation Plan for BAL-002-3.

## **B. Requirements and Measures**

- R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
  - 1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:
    - zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,or,
    - its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.
  - 1.2. document all Reportable Balancing Contingency Events using CR Form 1.

## BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

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**1.3.** deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

**1.3.1** is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- 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, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

**1.3.2** the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

**M1.** Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

**R2.** Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

## BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

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- M2.** Each Responsible Entity will have the following documentation to show compliance with Requirement R2:
- a dated Operating Process;
  - evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
  - evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.
- R3.** Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- M3.** Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

### 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 that it was compliant for the full-time period since the last audit.

The Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

## **BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event**

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If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

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

### **1.3. Compliance Monitoring and Assessment Processes:**

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

### **1.4. Additional Compliance Information**

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

**Table of Compliance Elements**

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
<b>R1.</b>	<p>The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period</p> <p>OR</p> <p>The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.</p>	<p>The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.</p>	<p>The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.</p>	<p>The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.</p>
<b>R2.</b>	<p>The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity’s Most Severe Single Contingency but failed to maintain</p>	N/A	<p>The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity’s Most Severe Single Contingency but failed to implement the Operating Process.</p>	<p>The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity’s Most Severe Single Contingency.</p>

**BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event**

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	annually the Operating Process.			
<b>R3.</b>	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

**D. Regional Variances**

None.

**E. Interpretations**

None.

**F. Associated Documents**

CR Form 1

BAL-002-3 Rationales

**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	
3	August 16, 2018	Adopted by NERC Board of Trustees	Revisions to address two FERC directives from Order No. 835
3	September 25, 2018	FERC Order approving BAL-002-3. Docket No. RD18-7-000	

**\* FOR INFORMATIONAL PURPOSES ONLY \***

**Effective Date of Standard: BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event**

**United States**

<b>Standard</b>	<b>Requirement</b>	<b>Effective Date of Standard</b>	<b>Phased In Implementation Date (if applicable)</b>	<b>Inactive Date</b>
BAL-002-3	All	04/01/2019		

**Exhibit B: List of Currently-Effective NERC Reliability Standards**

## Exhibit B: List of Currently Effective NERC Reliability Standards in Third Quarter 2018

### Resource and Demand Balancing (BAL)

BAL-001-2	<a href="#">Real Power Balancing Control Performance</a>
BAL-001-TRE-1	<a href="#">Primary Frequency Response in the ERCOT Region</a>
BAL-002-2(i)	<a href="#">Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event</a>
BAL-002-WECC-2a	<a href="#">Contingency Reserve</a>
BAL-003-1.1	<a href="#">Frequency Response and Frequency Bias Setting</a>
BAL-004-WECC-3	<a href="#">Automatic Time Error Correction</a>
BAL-005-0.2b	<a href="#">Automatic Generation Control</a>
BAL-006-2	<a href="#">Inadvertent Interchange</a>
BAL-502-RF-03	<a href="#">Planning Resource Adequacy Analysis, Assessment and Documentation</a>

### Communications (COM )

COM-001-3	<a href="#">Communications</a>
COM-002-4	<a href="#">Operating Personnel Communications Protocols</a>

### Critical Infrastructure Protection (CIP)

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

### Emergency Preparedness and Operations (EOP)

EOP-004-3	<a href="#">Event Reporting</a>
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EOP-005-2	<a href="#">System Restoration from Blackstart Resources</a>
EOP-006-2	<a href="#">System Restoration Coordination</a>
EOP-008-1	<a href="#">Loss of Control Center Functionality</a>
EOP-010-1	<a href="#">Geomagnetic Disturbance Operations</a>
EOP-011-1	<a href="#">Emergency Operations</a>

### **Facilities Design, Connections, and Maintenance (FAC )**

FAC-001-2	<a href="#">Facility Interconnection Requirements</a>
FAC-002-2	<a href="#">Facility Interconnection Studies</a>
FAC-003-4	<a href="#">Transmission Vegetation Management</a>
FAC-008-3	<a href="#">Facility Ratings</a>
FAC-010-3	<a href="#">System Operating Limits Methodology for the Planning Horizon</a>
FAC-011-3	<a href="#">System Operating Limits Methodology for the Operations Horizon</a>
FAC-013-2	<a href="#">Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon</a>
FAC-014-2	<a href="#">Establish and Communicate System Operating Limits</a>
FAC-501-WECC-2	<a href="#">Transmission Maintenance</a>

### **Interchange Scheduling and Coordination (INT)**

INT-004-3.1	<a href="#">Dynamic Transfers</a>
INT-006-4	<a href="#">Evaluation of Interchange Transactions</a>
INT-009-2.1	<a href="#">Implementation of Interchange</a>
INT-010-2.1	<a href="#">Interchange Initiation and Modification for Reliability</a>

### **Interconnection Reliability Operations and Coordination (IRO)**

IRO-001-4	<a href="#">Reliability Coordination – Responsibilities</a>
IRO-002-5	<a href="#">Reliability Coordination – Monitoring and Analysis</a>
IRO-006-5	<a href="#">Reliability Coordination — Transmission Loading Relief (TLR)</a>
IRO-006-EAST-2	<a href="#">Transmission Loading Relief Procedure for the Eastern Interconnection</a>
IRO-006-TRE-1	<a href="#">IROL and SOL Mitigation in the ERCOT Region</a>
IRO-006-WECC-2	<a href="#">Qualified Transfer Path Unscheduled Flow (USF) Relief</a>
IRO-008-2	<a href="#">Reliability Coordinator Operational Analyses and Real-time Assessments</a>

IRO-009-2	<a href="#">Reliability Coordinator Actions to Operate Within IROLs</a>
IRO-010-2	<a href="#">Reliability Coordinator Data Specification and Collection</a>
IRO-014-3	<a href="#">Coordination Among Reliability Coordinators</a>
IRO-017-1	<a href="#">Outage Coordination</a>
IRO-018-1(i)	<a href="#">Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities</a>

### **Modeling, Data, and Analysis (MOD )**

MOD-001-1a	<a href="#">Available Transmission System Capability</a>
MOD-004-1	<a href="#">Capacity Benefit Margin</a>
MOD-008-1	<a href="#">Transmission Reliability Margin Calculation Methodology</a>
MOD-020-0	<a href="#">Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators</a>
MOD-025-2	<a href="#">Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability</a>
MOD-026-1	<a href="#">Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions</a>
MOD-027-1	<a href="#">Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions</a>
MOD-028-2	<a href="#">Area Interchange Methodology</a>
MOD-029-2a	<a href="#">Rated System Path Methodology</a>
MOD-030-3	<a href="#">Flowgate Methodology</a>
MOD-031-2	<a href="#">Demand and Energy Data</a>
MOD-032-1	<a href="#">Data for Power System Modeling and Analysis</a>
MOD-033-1	<a href="#">Steady-State and Dynamic System Model Validation</a>

### **Nuclear (NUC)**

NUC-001-3	<a href="#">Nuclear Plant Interface Coordination</a>
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### **Personnel Performance, Training, and Qualifications (PER )**

PER-003-1	<a href="#">Operating Personnel Credentials</a>
PER-004-2	<a href="#">Reliability Coordination — Staffing</a>
PER-005-2	<a href="#">Operations Personnel Training</a>

### **Protection and Control (PRC)**

PRC-001-1.1(ii)	<a href="#"><u>System Protection Coordination</u></a>
PRC-002-2	<a href="#"><u>Disturbance Monitoring and Reporting Requirements</u></a>
PRC-004-5(i)	<a href="#"><u>Protection System Misoperation Identification and Correction</u></a>
PRC-004-WECC-2	<a href="#"><u>Protection System and Remedial Action Scheme Misoperation</u></a>
PRC-005-1.1b	<a href="#"><u>Transmission and Generation Protection System Maintenance and Testing</u></a>
PRC-005-6	<a href="#"><u>Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance</u></a>
PRC-006-3	<a href="#"><u>Automatic Underfrequency Load Shedding</u></a>
PRC-006-NPCC-1	<a href="#"><u>Automatic Underfrequency Load Shedding</u></a>
PRC-006-SERC-02	<a href="#"><u>Automatic Underfrequency Load Shedding Requirements</u></a>
PRC-008-0	<a href="#"><u>Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program</u></a>
PRC-010-2	<a href="#"><u>Undervoltage Load Shedding</u></a>
PRC-011-0	<a href="#"><u>Undervoltage Load Shedding System Maintenance and Testing</u></a>
PRC-015-1	<a href="#"><u>Remedial Action Scheme Data and Documentation</u></a>
PRC-016-1	<a href="#"><u>Remedial Action Scheme Misoperations</u></a>
PRC-017-1	<a href="#"><u>Remedial Action Scheme Maintenance and Testing</u></a>
PRC-018-1	<a href="#"><u>Disturbance Monitoring Equipment Installation and Data Reporting</u></a>
PRC-019-2	<a href="#"><u>Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection</u></a>
PRC-023-4	<a href="#"><u>Transmission Relay Loadability</u></a>
PRC-024-2	<a href="#"><u>Generator Frequency and Voltage Protective Relay Settings</u></a>
PRC-025-2	<a href="#"><u>Generator Relay Loadability</u></a>
PRC-026-1	<a href="#"><u>Relay Performance During Stable Power Swings</u></a>

### **Transmission Operations (TOP)**

TOP-001-4	<a href="#"><u>Transmission Operations</u></a>
TOP-002-4	<a href="#"><u>Operations Planning</u></a>
TOP-003-3	<a href="#"><u>Operational Reliability Data</u></a>
TOP-010-1(i)	<a href="#"><u>Real-time Reliability Monitoring and Analysis Capabilities</u></a>

### **Transmission Planning (TPL)**

TPL-001-4 [Transmission System Planning Performance Requirements](#)

TPL-007-1 [Transmission System Planned Performance for Geomagnetic Disturbance Events](#)

### **Voltage and Reactive (VAR)**

VAR-001-4.2 [Voltage and Reactive Control](#)

VAR-002-4.1 [Generator Operation for Maintaining Network Voltage Schedules](#)

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

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

# Glossary of Terms Used in NERC Reliability Standards

Updated July 3, 2018

This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through July 3, 2018.

This reference is divided into four sections, and each section is organized in alphabetical order.

**Subject to Enforcement**

**Pending Enforcement**

**Retired Terms**

**Regional Definitions**

The first three sections identify all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the Regional definitions section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards.

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 effective" date added following a final Order approving the definition.

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

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Actual Frequency (F <sub>A</sub> )	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016		7/1/2016	The Interconnection frequency measured in Hertz (Hz).
Actual Net Interchange (NI <sub>A</sub> )	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	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	<a href="#">Coordinate Operations</a>		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.
After the Fact	<a href="#">Project 2007-14</a>	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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		A contract or arrangement, either written or verbal and sometimes enforceable by law.
Alternative Interpersonal Communication	<a href="#">Project 2006-06</a>		11/7/2012	4/16/2015	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	<a href="#">Project 2007-07</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	<a href="#">Version 0 Reliability Standards</a>	ACE	12/19/2012	10/16/2013	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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Area Interchange Methodology	<a href="#">Project 2006-07</a>		8/22/2008	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	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	10/1/2014	The state where a Request for Interchange (initial or revised) has been submitted for approval.
Attaining Balancing Authority	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	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	<a href="#">Version 0 Reliability Standards</a>	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 Time Error Correction ( $I_{ATEC}$ ) <i>continued below...</i>	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016		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> $I_{ATEC} = \frac{PI_{accum}^{in/off\ peak}}{(1-Y) \cdot H}$ <p>when operating in Automatic Time error correction Mode. The absolute value of <math>I_{ATEC}</math> shall not exceed <math>L_{max}</math>.</p> <p><math>I_{ATEC}</math> shall be zero when operating in any other AGC mode.</p> <ul style="list-style-type: none"> <li><math>L_{max}</math> is the maximum value allowed for <math>I_{ATEC}</math> set by each BA between <math>0.2 \cdot  B_i </math> and <math>L10</math>, <math>0.2 \cdot  B_i  \leq L_{max} \leq L10</math>.</li> <li><math>L_{10} = 1.65 \cdot \epsilon_{10} \sqrt{(-10B_i)(-10B_s)}</math>.</li> <li><math>\epsilon_{10}</math> 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, <math>\epsilon_{10}</math>, is the same for every Balancing Authority Area within an Interconnection.</li> </ul>
Automatic Time Error Correction ( $I_{ATEC}$ )	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016		7/1/2016	<ul style="list-style-type: none"> <li><math>Y = B_i / B_s</math>.</li> <li><math>H</math> = Number of hours used to payback primary inadvertent interchange energy. The value of <math>H</math> is set to 3.</li> <li><math>B_i</math> = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).</li> <li><math>B_s</math> = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).</li> <li>Primary Inadvertent Interchange (<math>PII_{hourly}</math>) is <math>(1-Y) \cdot (II_{actual} - B_i \cdot \Delta TE/6)</math></li> <li><math>II_{actual}</math> is the hourly Inadvertent Interchange for the last hour.</li> <li><math>\Delta TE</math> is the hourly change in system Time Error as distributed by the Interconnection time monitor, where: <math>\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t) \cdot (TE_{offset})</math></li> </ul>

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Automatic Time Error Correction ( $I_{ATEC}$ )	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016		7/1/2016	<ul style="list-style-type: none"> <li>• <math>TD_{adj}</math> is the Reliability Coordinator adjustment for differences with Interconnection time monitor control center clocks.</li> <li>• <math>t</math> is the number of minutes of manual Time Error Correction that occurred during the hour.</li> <li>• <math>TE_{offset}</math> is 0.000 or +0.020 or -0.020.</li> <li>• <math>PII_{accum}</math> is the Balancing Authority Area's accumulated PIIhourly in MWh. An On-Peak and Off-Peak accumulation accounting is required, where:  <math display="block">PII_{accum}^{on/offpeak} = \text{last period's } PII_{accum}^{on/offpeak} + PII_{hourly}</math> </li> </ul>
Available Flowgate Capability	<a href="#">Project 2006-07</a>	AFC	8/22/2008	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	<a href="#">Project 2006-07</a>	ATC	8/22/2008	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	<a href="#">Project 2006-07</a>	ATCID	8/22/2008	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.
Balancing Authority	<a href="#">Version 0 Reliability Standards</a>	BA	2/8/2005	3/16/2007		The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area	<a href="#">Version 0 Reliability Standards</a>		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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Balancing Contingency Event	<a href="#">Project 2010-14.1 Phase 1</a>		11/5/2015	1/19/2017	1/1/2018	<p>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.</p> <p>A. Sudden loss of generation:</p> <ul style="list-style-type: none"> <li>a. Due to <ul style="list-style-type: none"> <li>i. unit tripping, or</li> <li>ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or</li> <li>iii. sudden unplanned outage of transmission Facility;</li> </ul> </li> <li>b. And, that causes an unexpected change to the responsible entity's ACE;</li> </ul> <p>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.</p> <p>C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.</p>
Base Load	<a href="#">Version 0 Reliability</a>		2/8/2005	3/16/2007		The minimum amount of electric power delivered or required over a given period at a constant rate.
BES Cyber Asset	<a href="#">Project 2014-02</a>	BCA	2/12/2015	1/21/2016	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	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	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.
BES Cyber System Information	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Blackstart Resource	<a href="#">Project 2015-04</a>		11/5/2015	1/21/2016	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	<a href="#">Project 2006-07</a>		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, 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).
Bulk Electric System (continued below)	<a href="#">Project 2010-17</a>	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Implementation Plan for Phase 2 Compliance obligations.)	<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><b>Inclusions:</b></p> <ul style="list-style-type: none"> <li>• 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.</li> <li>• 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"> <li>a) Gross individual nameplate rating greater than 20 MVA. Or,</li> <li>b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.</li> </ul> </li> <li>• I3 - Blackstart Resources identified in the Transmission Operator's restoration plan.</li> </ul>

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Bulk Electric System (continued below)	<a href="#">Project 2010-17</a>	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Implementation Plan for Phase 2 Compliance obligations.)	<ul style="list-style-type: none"> <li>• 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:               <ul style="list-style-type: none"> <li>a) The individual resources, and</li> <li>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.</li> </ul> </li> <li>• 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.</li> </ul>
Bulk Electric System (continued)	<a href="#">Project 2010-17</a>	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Implementation Plan for Phase 2 Compliance obligations.)	<p><b>Exclusions:</b></p> <ul style="list-style-type: none"> <li>• 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"> <li>a) Only serves Load. Or,</li> <li>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,</li> <li>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).</li> </ul> </li> </ul> <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.            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>
Bulk Electric System (continued)	<a href="#">Project 2010-17</a>	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Implementation Plan for Phase 2 Compliance obligations.)	<ul style="list-style-type: none"> <li>• 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.</li> </ul>

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Bulk Electric System (continued)	<a href="#">Project 2010-17</a>	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Implementation Plan for Phase 2 Compliance obligations.)	<ul style="list-style-type: none"> <li>• 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"> <li>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 generation greater than 75 MVA (gross nameplate rating);</li> <li>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</li> </ul> </li> </ul>
Bulk Electric System (continued)	<a href="#">Project 2010-17</a>	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Implementation Plan for Phase 2 Compliance obligations.)	<ul style="list-style-type: none"> <li>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).</li> <li>• E4 – Reactive Power devices installed for the sole benefit of a retail customer(s).</li> </ul> <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	<a href="#">Project 2015-04</a>		11/5/2015	1/21/2016	7/1/2016	<p>Bulk-Power System:</p> <p>(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and</p> <p>(B) electric energy from generation facilities needed to maintain transmission system reliability.</p> <p>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.)</p>
Burden	<a href="#">Version 0 Reliability Standards</a>		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.
Bus-tie Breaker	<a href="#">Project 2006-02</a>		8/4/2011	10/17/2013	1/1/2015	A circuit breaker that is positioned to connect two individual substation bus configurations.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Capacity Benefit Margin	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Project 2006-07</a>	CBMID	11/13/2008	11/24/2009		A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2015-04</a>		11/5/2015	1/21/2016	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.
CIP Exceptional Circumstance	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	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	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Composite Confirmed Interchange	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	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	<a href="#">2010-05.1</a>		8/14/2014	5/13/2015	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	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	10/1/2014	The state where no party has denied and all required parties have approved the Arranged Interchange.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Congestion Management Report	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2006-02</a>		8/4/2011	10/17/2013	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.
Constrained Facility	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2010-14.1 Phase 1</a>		11/5/2015	1/19/2017	1/1/2018	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	<a href="#">Project 2010-14.1 Phase 1</a>		11/5/2015	1/19/2017	1/1/2018	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"> <li>• 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.</li> <li>• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.</li> </ul>
Contingency Reserve Restoration Period	<a href="#">Project 2010-14.1 Phase 1</a>		11/5/2015	1/19/2017	1/1/2018	A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
Contact Path	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Center	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	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	<a href="#">Version 0 Reliability Standards</a>	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.

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Corrective Action Plan	<a href="#">Phase III-IV Planning Standards - Archive</a>		2/7/2006	3/16/2007		A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path	<a href="#">Phase III-IV Planning Standards - Archive</a>		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.
Curtailment	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	7/1/2016	Programmable electronic devices, including the hardware, software, and data in those devices.
Cyber Security Incident	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	7/1/2016	A malicious act or suspicious event that: <ul style="list-style-type: none"> <li>• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or,</li> <li>• Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.</li> </ul>
Delayed Fault Clearing	<a href="#">Determine Facility Ratings, Operating Limits, and Transfer Capabilities</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management	<a href="#">Project 2010-04</a>	DSM	5/6/2014	2/19/2015	7/1/2016	All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.
Dial-up Connectivity	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	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	<a href="#">Project 2008-06</a>	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.
Dispatch Order	<a href="#">Project 2006-07</a>		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, each generator is ranked by priority.
Dispersed Load by Substations	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.

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Distribution Factor	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Project 2015-04</a>	DP	11/5/2015	1/21/2016	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.
Disturbance	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		<ol style="list-style-type: none"> <li>1. An unplanned event that produces an abnormal system condition.</li> <li>2. Any perturbation to the electric system.</li> <li>3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.</li> </ol>
Disturbance Control Standard	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Phase III-IV Planning Standards</a>	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 recorders* :</p> <ul style="list-style-type: none"> <li>• Sequence of event recorders which record equipment response to the event</li> <li>• Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays.</li> <li>• 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</li> </ul> <p>*Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.</p>
Dynamic Interchange Schedule or Dynamic Schedule	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	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	<a href="#">Version 0 Reliability Standards</a>		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.
Economic Dispatch	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2008-06 Order 706</a>	EACMS	11/26/2012	11/22/2013	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	<a href="#">Project 2008-06 Order 706</a>	EAP	11/26/2012	11/22/2013	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.

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Electrical Energy	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Security Perimeter	<a href="#">Project 2008-06 Order 706</a>	ESP	11/26/2012	11/22/2013	7/1/2016	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.
Element	<a href="#">Project 2015-04</a>		11/5/2015	1/21/2016	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2007-14 Coordinate Interchange</a>	Emergency RFI	10/29/2008	12/17/2009		Request for Interchange to be initiated for Emergency or Energy Emergency conditions.
Energy Emergency	<a href="#">Version 0</a>		11/13/2014	11/19/2015	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.
Equipment Rating	<a href="#">Determine Facility Ratings, Operating Limits, and Transfer Capabilities</a>		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	<a href="#">Project 2008-06 Order 706</a>		11/26/2012	11/22/2013	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	<a href="#">Project 2006-07</a>	ETC	8/22/2008	11/24/2009		Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.
Facility	<a href="#">Determine Facility Ratings, Operating Limits, and Transfer Capabilities</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2007-07</a>		2/7/2006	3/16/2007		The likelihood that a fire will ignite or spread in a particular geographic area.

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Firm Demand	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2007-07</a>		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	<a href="#">Project 2006-07</a>		8/22/2008	11/24/2009		1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology	<a href="#">Version 0 Reliability Standards</a>		8/22/2008	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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias	<a href="#">Version 0 Reliability Standards</a>		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.
Frequency Bias Setting	<a href="#">Project 2007-12</a>		2/7/2013	1/16/2014	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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		A change in Interconnection frequency.
Frequency Error	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The difference between the actual and scheduled frequency. ( $F_A - F_S$ )
Frequency Regulation	<a href="#">Version 0 Reliability Standards</a>		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.

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Frequency Response	<a href="#">Version 0 Reliability Standards</a>		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).
Frequency Response Measure	<a href="#">Project 2007-12</a>	FRM	2/7/2013	1/16/2014	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	<a href="#">Project 2007-12</a>	FRO	2/7/2013	1/16/2014	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.
Frequency Response Sharing Group	<a href="#">Project 2007-12</a>	FRSG	2/7/2013	1/16/2014	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	<a href="#">Version 0 Reliability Standards</a>	GOP	11/5/2015	1/21/2016	7/1/2016	The entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	<a href="#">Version 0 Reliability Standards</a>	GO	11/5/2015	1/21/2016	7/1/2016	Entity that owns and maintains generating Facility(ies).
Generator Shift Factor	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Version 0 Reliability Standards</a>	GLDF	2/8/2005	3/16/2007		The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Generation Capability Import Requirement	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>	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	<a href="#">Project 2013-03 Geomagnetic Disturbance Mitigation</a>	GMD	12/17/2014	9/22/2016	7/1/2017	Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.
Host Balancing Authority	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		Data measured on a Clock Hour basis.
Implemented Interchange	<a href="#">Coordinate Interchange</a>		5/2/2006	3/16/2007		The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.

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Inadvertent Interchange	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS)
Independent Power Producer	<a href="#">Version 0 Reliability Standards</a>	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.	<a href="#">Project 2007-07</a>	IEEE	2/7/2006	3/16/2007		
Interactive Remote Access	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	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	<a href="#">Coordinate Interchange</a>		5/2/2006	3/16/2007		Energy transfers that cross Balancing Authority boundaries.
Interchange Authority	<a href="#">Project 2015-04</a>	IA	11/5/2015	1/21/2016	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.
Interchange Distribution Calculator	<a href="#">Version 0 Reliability Standards</a>		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 (IME)	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service	<a href="#">Project 2015-04</a>		11/5/2015	1/21/2016	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.

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Interconnection	<a href="#">Project 2015-04</a>		11/5/2015	1/21/2016	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.
Interconnection Reliability Operating Limit	<a href="#">Determine Facility Ratings, Operating Limits, and Transfer Capabilities</a>	IROL	11/1/2006	12/27/2007		A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T <sub>v</sub>	<a href="#">Determine Facility Ratings, Operating Limits, and Transfer Capabilities</a>	IROL T <sub>v</sub>	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 <sub>v</sub> shall be less than or equal to 30 minutes.
Intermediate Balancing Authority	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
Intermediate System	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013	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	<a href="#">Project 2006-06</a>		11/7/2012	4/16/2015	10/1/2015	Any medium that allows two or more individuals to interact, consult, or exchange information.
Interruptible Load or Interruptible Demand	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		Automatic Generation Control of jointly owned units by two or more Balancing Authorities.
Limiting Element	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		An end-use device or customer that receives power from the electric system.
Load Shift Factor	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Project 2015-04</a>	LSE	11/5/2015	1/21/2016	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	<a href="#">Project 2006-02</a>		8/4/2011	10/17/2013	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.

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Low Impact BES Cyber System Electronic Access Point	<a href="#">Project 2014-02</a>	LEAP	2/12/2015	1/21/2016	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.
Low Impact External Routable Connectivity	<a href="#">Project 2014-02</a>	LERC	2/12/2015	1/21/2016	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	<a href="#">Project 2006-08 Reliability Coordination - Transmission Loading Relief</a>		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	<a href="#">Project 2007-07</a>	MVCD	11/3/2011	3/21/2013	7/1/2014	The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.
Misoperation	<a href="#">Project 2010-05.1</a>		8/14/2014	5/13/2015	7/1/2016	The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation: <b>1. Failure to Trip – During Fault</b> – 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. <b>2. Failure to Trip – Other Than Fault</b> – 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. <b>3. Slow Trip – During Fault</b> – 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. (continued below...)
Misoperation (continued...)	<a href="#">Project 2010-05.1</a>		8/14/2014	5/13/2015	7/1/2016	<b>4. Slow Trip – Other Than Fault</b> – 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. <b>5. Unnecessary Trip – During Fault</b> – An unnecessary Composite Protection System operation for a Fault condition on another Element. <b>6. Unnecessary Trip – Other Than Fault</b> – 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.

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Most Severe Single Contingency	<a href="#">Project 2010-14.1 Phase 1</a>	MSSC	11/5/2015	1/19/2017	1/1/2018	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).
Native Balancing Authority	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon	<a href="#">Project 2010-10</a>		1/24/2011	11/17/2011		The transmission planning period that covers Year One through five.
Net Actual Interchange	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2006-02</a>		8/4/2011	10/17/2013	1/1/2015	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

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Normal Clearing	<a href="#">Determine Facility Ratings, Operating Limits, and Transfer Capabilities</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2009-08</a>		5/2/2007	10/16/2008		Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Off-site Power Supply (Off-site Power)	<a href="#">Project 2009-08</a>		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	<a href="#">Project 2009-08</a>	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	<a href="#">Project 2009-08</a>	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.
Off-Peak	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Project 2007-02</a>		5/6/2014	4/16/2015	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.)

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Operating Plan	<a href="#">Coordinate Operations</a>		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	<a href="#">Coordinate Operations</a>		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	<a href="#">Coordinate Operations</a>		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	<a href="#">Version 0 Reliability Standards</a>		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.
Operating Reserve – Spinning	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The portion of Operating Reserve consisting of: <ul style="list-style-type: none"> <li>• Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or</li> <li>• Load fully removable from the system within the Disturbance Recovery Period following the contingency event.</li> </ul>
Operating Reserve – Supplemental	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The portion of Operating Reserve consisting of: <ul style="list-style-type: none"> <li>• 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</li> <li>• Load fully removable from the system within the Disturbance Recovery Period following the contingency event.</li> </ul>
Operating Voltage	<a href="#">Project 2007-07</a>		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	<a href="#">Project 2014-03</a>	OPA	11/13/2014	11/19/2015	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.)
Operations Support Personnel	<a href="#">Project 2010-01</a>		2/6/2014	6/19/2014	7/1/2016	Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, <sup>1</sup> in direct support of Real-time operations of the Bulk Electric System.

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Outage Transfer Distribution Factor	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>	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	<a href="#">Version 0 Reliability Standards</a>		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.
Participation Factors	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period	<a href="#">Determine Facility Ratings, Operating Limits, and Transfer Capabilities</a>		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	<a href="#">Project 2008-06 Cyber Security Order 706</a>	PACS	11/26/2012	11/22/2013	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	<a href="#">Project 2008-06 Cyber Security Order 706</a>	PSP	11/26/2012	11/22/2013	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.
Planning Assessment	<a href="#">Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans</a>		8/4/2011	10/17/2013	1/1/2015	Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	7/1/2016	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Planning Coordinator	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>	PC	8/22/2008	11/24/2009		See Planning Authority.
Point of Delivery	<a href="#">Version 0 Reliability Standards</a>	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.

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Point of Receipt	<a href="#">Project 2015-04 Alignment of Terms</a>	POR	11/5/2015	1/21/2016	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	<a href="#">Version 0 Reliability Standards</a>	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.
Power Transfer Distribution Factor	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>	PTDF	8/22/2008	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	<a href="#">Project 2010-14.1 Phase 1</a>		11/5/2015	1/19/2017	1/1/2018	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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protected Cyber Assets	<a href="#">Project 2014-02</a>	PCA	2/12/2015	1/21/2016	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	<a href="#">Project 2007-17 Protection System Maintenance and Testing</a>		11/19/2010	2/3/2012	4/1/2013	Protection System – <ul style="list-style-type: none"> <li>• Protective relays which respond to electrical quantities,</li> <li>• Communications systems necessary for correct operation of protective functions</li> <li>• Voltage and current sensing devices providing inputs to protective relays,</li> <li>• Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and</li> <li>• Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.</li> </ul>
Protection System Maintenance Program (PRC-005-6)	<a href="#">Project 2007-17.4 PRC-005 FERC Order No 803 Directive</a>	PSMP	11/5/2015	12/18/2015	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"> <li>• Verify — Determine that the Component is functioning correctly.</li> <li>• Monitor — Observe the routine in-service operation of the Component.</li> <li>• Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems.</li> <li>• Inspect — Examine for signs of Component failure, reduced performance or degradation.</li> <li>• Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.</li> </ul>

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Pseudo-Tie	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	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).
Purchasing-Selling Entity	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2007-07 Transmission Vegetation Management</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The operational limits of a transmission system element under a set of specified conditions.
Rated System Path Methodology	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>		8/22/2008	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	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	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).
Real Power	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	7/1/2016	The portion of electricity that supplies energy to the Load.
Real-time	<a href="#">Coordinate Operations</a>		2/7/2006	3/16/2007		Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment	<a href="#">Project 2014-03</a>		11/13/2014	Revised definition. 11/19/2015	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.)

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Receiving Balancing Authority	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The Balancing Authority importing the Interchange.
Regional Reliability Organization	<a href="#">Version 0 Reliability Standards</a>	RRO	2/8/2005	3/16/2007		1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Reserve Sharing Group	<a href="#">Project 2010-14.1 Phase 1</a>		8/15/2013	4/16/2015	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2008-12 Coordinate Interchange Standards</a>		2/6/2014	6/30/2014	10/1/2014	A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
Reliability Adjustment RFI	<a href="#">Project 2007-14 Coordinate Interchange - Timing Table</a>		10/29/2008	12/17/2009		Request to modify an Implemented Interchange Schedule for reliability purposes.
Reliability Coordinator	<a href="#">Project 2015-04 Alignment of Terms</a>	RC	11/5/2015	1/21/2016	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	<a href="#">Version 0 Reliability Standards</a>		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.

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Reliability Coordinator Information System	<a href="#">Version 0 Reliability Standards</a>	RCIS	2/8/2005	3/16/2007		The system that Reliability Coordinators use to post messages and share operating information in real time.
Reliability Standard	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	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	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	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	<a href="#">Project 2010-05.2</a>	RAS	11/13/2014	11/19/2015	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"> <li>• Meet requirements identified in the NERC Reliability Standards;</li> <li>• Maintain Bulk Electric System (BES) stability;</li> <li>• Maintain acceptable BES voltages;</li> <li>• Maintain acceptable BES power flows;</li> <li>• Limit the impact of Cascading or extreme events.</li> </ul> <p>The following do not individually constitute a RAS:</p> <ol style="list-style-type: none"> <li>a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements</li> <li>b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays</li> <li>c. Out-of-step tripping and power swing blocking</li> <li>d. Automatic reclosing schemes</li> <li>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</li> </ol>

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Remedial Action Scheme <i>Continued</i>	<a href="#">Project 2010-05.2</a>	RAS	11/13/2014	11/19/2015	4/1/2017	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)
Remedial Action Scheme <i>Continued</i>	<a href="#">Project 2010-05.2</a>	RAS	11/13/2014	11/19/2015	4/1/2017	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	<a href="#">Project 2014-02</a>		2/12/2015	1/21/2016	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.
Reportable Balancing Contingency Event	<a href="#">Project 2010-14.1 Phase 1</a>		11/5/2015	1/19/2017	1/1/2018	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"> <li>• Eastern Interconnection – 900 MW</li> <li>• Western Interconnection – 500 MW</li> <li>• ERCOT – 800 MW</li> <li>• Quebec – 500 MW</li> </ul>

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Reportable Cyber Security Incident	<a href="#">Project 2008-06 Cyber Security Order 706 V5 CIP Standards</a>		11/26/2012	11/22/2013	7/1/2016	A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.
Reportable Disturbance	<a href="#">Version 0 Reliability Standards</a>		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.
Reporting ACE	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016		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:  <math display="block">\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}</math> Reporting ACE is calculated in the Western Interconnection as follows:  <math display="block">\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}</math> Where:</p> <ul style="list-style-type: none"> <li>• <math>NI_A</math> = Actual Net Interchange.</li> <li>• <math>NI_S</math> = Scheduled Net Interchange.</li> <li>• <math>B</math> = Frequency Bias Setting.</li> <li>• <math>F_A</math> = Actual Frequency.</li> <li>• <math>F_S</math> = Scheduled Frequency.</li> <li>• <math>I_{ME}</math> = Interchange Meter Error.</li> <li>• <math>I_{ATEC}</math> = Automatic Time Error Correction.</li> </ul>
Reporting ACE (continued)	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016		7/1/2016	<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"> <li>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;</li> <li>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;</li> <li>3. The use of a common Scheduled Frequency <math>F_S</math> for all BAAs at all times; and,</li> <li>4. Excludes metering or computational errors. (The inclusion and use of the <math>I_{ME}</math> term corrects for known metering or computational errors.)</li> </ol>
Request for Interchange	<a href="#">Project 2008-12 Coordinate Interchange</a>	RFI	2/6/2014	6/30/2014	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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Reserve Sharing Group	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	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.
Reserve Sharing Group Reporting ACE	<a href="#">Project 2010-14.1 Phase 1</a>		11/5/2015	1/19/2017	1/1/2018	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	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2010-07</a>	ROW	5/9/2012	3/21/2013	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.
Scenario	<a href="#">Coordinate Operations</a>		2/7/2006	3/16/2007		Possible event.
Schedule	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		60.0 Hertz, except during a time correction.
Scheduled Net Interchange (NI <sub>s</sub> )	<a href="#">Project 2010-14.2.1 Phase 2</a>		2/11/2016		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Sending Balancing Authority	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		The Balancing Authority exporting the Interchange.
Sink Balancing Authority	<a href="#">Project 2008-12 Coordinate Interchange Standards</a>		2/6/2014	6/30/2014	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	<a href="#">Project 2008-12 Coordinate Interchange Standards</a>		2/6/2014	6/30/2014	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)	<a href="#">Project 2010-05.2</a>	SPS	5/5/2016	6/23/2016	4/1/2017	See "Remedial Action Scheme"
Spinning Reserve	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		Unloaded generation that is synchronized and ready to serve additional demand.
Stability	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage	<a href="#">Project 2007-07 Transmission Vegetation Management</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		A combination of generation, transmission, and distribution components.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
System Operating Limit	<a href="#">Project 2015-04 Alignment of Terms</a>	SOL	11/5/2015	1/21/2016	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"> <li>• Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)</li> <li>• transient stability ratings (applicable pre- and post- Contingency stability limits)</li> <li>• voltage stability ratings (applicable pre- and post-Contingency voltage stability)</li> <li>• system voltage limits (applicable pre- and post-Contingency voltage limits)</li> </ul>
System Operator	<a href="#">Project 2010-01 Training</a>		2/6/2014	6/19/2014	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		A circuit connecting two Balancing Authority Areas.
Tie Line Bias	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		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.
Time Error Correction	<a href="#">Version 0 Reliability Standards</a>		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) Log  (NERC added the spelled out term for TLR Log for clarification purposes.)	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>	TFC	8/22/2008	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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Total Internal Demand	<a href="#">Project 2010-04 Demand Data (MOD C)</a>		5/6/2014	2/19/2015	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	<a href="#">Version 0 Reliability Standards</a>	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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		See Interchange Transaction.
Transfer Capability	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		See Distribution Factor.
Transient Cyber Asset	<a href="#">Project 2014-02</a>		2/12/2015	1/21/2016	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	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	7/1/2016	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	<a href="#">Project 2007-07 Transmission Vegetation Management</a>		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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Transmission Operator	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	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.
Transmission Operator Area	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>		8/22/2008	11/24/2009		The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	7/1/2016	The entity that owns and maintains transmission Facilities.
Transmission Planner	<a href="#">Project 2015-04 Alignment of Terms</a>		11/5/2015	1/21/2016	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	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>		8/22/2008	11/24/2009		A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service	<a href="#">Version 0 Reliability Standards</a>		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	<a href="#">Project 2015-04 Alignment of Terms</a>	TSP	11/5/2015	1/21/2016	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	<a href="#">Project 2008-02 Undervoltage Load Shedding &amp; Underfrequency Load Shedding</a>	UVLS Program	11/13/2014	11/19/2015	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	<a href="#">Project 2007-07 Transmission Vegetation Management</a>		2/7/2006	3/16/2007		All plant material, growing or not, living or dead.
Vegetation Inspection	<a href="#">Project 2010-07</a>		5/9/2012	3/21/2013	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	<a href="#">Version 0 Reliability Standards</a>		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.

**SUBJECT TO ENFORCEMENT**

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Year One	<a href="#">Project 2010-10 FAC Order 729</a>		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.

PENDING ENFORCEMENT

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Automatic Generation Control	<a href="#">Project 2010-14.2.1. Phase 2</a>	AGC	2/11/2016	9/20/2017	1/1/2019	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.
Balancing Authority	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016	9/20/2017	1/1/2019	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.
Operational Planning Analysis	<a href="#">Project 2007-06.2 Phase 2 of System Protection Coordination</a>	OPA	8/11/2016	6/7/2018	10/1/2020	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.)
Protection System Coordination Study	<a href="#">Project 2007-06 System Protection Coordination</a>		11/5/2015	6/7/2018	10/1/2020	An analysis to determine whether Protection Systems operate in the intended sequence during Faults.
Pseudo-Tie	<a href="#">Project 2010-14.2.1. Phase 2</a>		2/11/2016	9/20/2017	1/1/2019	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).
Real-time Assessment	<a href="#">Project 2007-06.2 Phase 2 of System Protection Coordination</a>	RTA	8/11/2016		10/1/2020	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.)

PENDING ENFORCEMENT

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Removable Media	<a href="#">Project 2016-02 Modifications to CIP Standards</a>		2/9/2017	4/19/2018	1/1/2020	<p>Storage media that:</p> <ol style="list-style-type: none"> <li>1. are not Cyber Assets,</li> <li>2. are capable of transferring executable code,</li> <li>3. can be used to store, copy, move, or access data, and</li> <li>4. are directly connected for 30 consecutive calendar days or less to a:                             <ul style="list-style-type: none"> <li>• BES Cyber Asset,</li> <li>• network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or</li> <li>• Protected Cyber Asset associated with high or medium impact BES Cyber Systems.</li> </ul> </li> </ol> <p>Examples of Removable Media 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.</p>
Transient Cyber Asset	<a href="#">Project 2016-02 Modifications to CIP Standards</a>	TCA	2/9/2017	4/19/2018	1/1/2020	<p>A Cyber Asset that is:</p> <ol style="list-style-type: none"> <li>1. capable of transmitting or transferring executable code,</li> <li>2. not included in a BES Cyber System,</li> <li>3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and</li> <li>4. 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:                             <ul style="list-style-type: none"> <li>• BES Cyber Asset,</li> <li>• network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or</li> <li>• PCA associated with high or medium impact BES Cyber Systems.</li> </ul> </li> </ol> <p>Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.</p>

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Adjacent Balancing Authority	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		9/30/2014	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact	<a href="#">Project 2006-06</a>		8/4/2011	NERC withdrew the related petition			The impact of an event that results in Bulk Electric System instability or Cascading.
Area Control Error	<a href="#">Version 0 Reliability Standards</a>	ACE	2/8/2005	3/16/2007		3/31/2014	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.
Arranged Interchange	<a href="#">Coordinate Interchange</a>		5/2/2006	3/16/2007		9/30/2014	The state where the Interchange Authority has received the Interchange information (initial or revised).
ATC Path	<a href="#">Project 2006-07</a>		8/22/2008	Not approved; Modification directed			Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path. (See 18 CFR 37.6(b)(1))
Available Transfer Capability	<a href="#">Version 0 Reliability Standards</a>	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.
BES Cyber Asset	<a href="#">Project 2008-06</a>		11/26/2012	11/22/2013		6/30/2016	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. (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.)
Blackstart Capability Plan	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		7/1/2013 Will be retired when EOP-005-2 becomes enforceable	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Blackstart Resource	<a href="#">Project 2006-03</a>		8/5/2009	3/17/2011		6/30/2016	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.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Bulk Electric System	<a href="#">Version 0 Reliability Standards</a>	BES	2/8/2005	3/16/2007		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.
Bulk Electric System  (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.)	<a href="#">Project 2010-17</a>	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	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"> <li>• 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.</li> <li>• 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.</li> <li>• I3 - Blackstart Resources identified in the Transmission Operator's restoration plan.</li> <li>• 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.</li> </ul>
Bulk Electric System  (Continued)	<a href="#">Project 2010-17</a>	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	<b>I5</b> –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. <b>Exclusions:</b> <ul style="list-style-type: none"> <li>• <b>E1</b> - 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"> <li>a) Only serves Load. Or,</li> <li>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,</li> <li>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).</li> </ul> </li> </ul> <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>

## Retired Terms

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Bulk Electric System (Continued)	<a href="#">Project 2010-17</a>	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	<ul style="list-style-type: none"> <li>• <b>E2</b> - 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.</li> <li>• <b>E3</b> - 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:</li> </ul>
Bulk Electric System (Continued)	<a href="#">Project 2010-17</a>	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	<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"> <li>• <b>E4</b> – 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.</li> </ul>
Bulk-Power System	<a href="#">Project 2012-08.1 Phase 1</a>		5/9/2013	7/9/2013		6/30/2016	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.

## Retired Terms

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Business Practices	<a href="#">Project 2006-07</a>		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.
Cascading	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		6/30/2016	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	<a href="#">Determine Facility Ratings, Operating Limits, and Transfer Capabilities</a>		11/1/2006 Withdrawn 2/12/2008			FERC Remanded 12/27/2007	<del>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 predetermined area.</del>
Confirmed Interchange	<a href="#">Coordinate Interchange</a>		5/2/2006	3/16/2007			The state where the Interchange Authority has verified the Arranged Interchange.
Contingency Reserve	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		12/31/2017	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.
Critical Assets	<a href="#">Cyber Security (Permanent)</a>		5/2/2006	1/18/2008		6/30/2016	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	<a href="#">Cyber Security (Permanent)</a>		5/2/2006	1/18/2008		6/30/2016	Cyber Assets essential to the reliable operation of Critical Assets.
Cyber Assets	<a href="#">Cyber Security (Permanent)</a>		5/2/2006	1/18/2008		6/30/2016	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Security Incident	<a href="#">Cyber Security (Permanent)</a>		5/2/2006	1/18/2008		6/30/2016	Any malicious act or suspicious event that: <ul style="list-style-type: none"> <li>• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,</li> <li>• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.</li> </ul>
Demand-Side Management	<a href="#">Version 0 Reliability Standards</a>	DSM	2/8/2005	3/16/2007		6/30/2016	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.

Retired Terms							
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Distribution Provider	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		6/30/2016	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.
Dynamic Interchange Schedule or Dynamic Schedule	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		9/30/2014	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.
Electronic Security Perimeter	<a href="#">Cyber Security (Permanent)</a>	ESP	5/2/2006	1/18/2008		6/30/2016	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		6/30/2016	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.
Energy Emergency	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		3/31/2017	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers’ expected energy requirements.
Flowgate	<a href="#">Version 0 Reliability Standards</a>		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.
Frequency Bias Setting	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		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.
Generator Operator		GOP	2/8/2005	3/16/2007		6/30/2016	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner		GO	2/8/2005	3/16/2007		6/30/2016	Entity that owns and maintains generating units.
Interchange Authority		IA	5/2/2006	3/16/2007		6/30/2016	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.
Interconnected Operations Service	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007			A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		6/30/2016	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection	<a href="#">Project 2010-14.1 Phase 1</a>		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.

Retired Terms							
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Interconnection Reliability Operating Limit	<a href="#">Version 0 Reliability Standards</a>	IROL	2/8/2005	3/16/2007		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.
Intermediate Balancing Authority	<a href="#">Version 0 Reliability Standards</a>		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.
Load-Serving Entity	<a href="#">Version 0 Reliability Standards</a>		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.
Misoperation	<a href="#">Phase III - IV Planning Standards - Archive</a>		2/7/2006	3/16/2007		6/30/2016	<ul style="list-style-type: none"> <li>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.</li> <li>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).</li> <li>Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.</li> </ul>
Operational Planning Analysis	<a href="#">Operate Within Interconnection Reliability Operating Limits</a>		10/17/2008	3/17/2011		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.).
Operational Planning Analysis	<a href="#">Project 2008-12</a>		2/6/2014	6/30/2014	10/1/2014	12/31/2016	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.).
Physical Security Perimeter	<a href="#">Cyber Security (Permanent)</a>	PSP	5/2/2006	1/18/2008		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.
Planning Authority	<a href="#">Version 0 Reliability Standards</a>	PA	2/8/2005	3/16/2007			The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Point of Receipt	<a href="#">Version 0 Reliability Standards</a>	POR	2/8/2005	3/16/2007		6/30/2016	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.

Retired Terms							
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Postback	<a href="#">Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions</a>		8/22/2008	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.
Protected Cyber Assets	<a href="#">Project 2008-06 Cyber Security Order 706</a>	PCA	11/26/2012	11/22/2013		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.
Protection System	<a href="#">Phase III-IV Planning Standards - Archive</a>		2/7/2006	3/17/2007		4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Protection System Maintenance Program (PRC-005-2)	<a href="#">Project 2007-17 Protection System Maintenance and Testing</a>	PSMP	11/7/2012	12/19/2013		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.

Retired Terms							
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Protection System Maintenance Program (PRC-005-3)	<a href="#">Project 2007-17.2 Protection System Maintenance and Testing - Phase 2</a>	PSMP	11/7/2013	1/22/2015	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.
Protection System Maintenance Program (PRC-005-4)	<a href="#">Project 2014-01 Standards Applicability for Dispersed Generation Resources</a>	PSMP	11/13/2014	9/17/2015	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: • 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	<a href="#">Version 0 Reliability Standards</a>		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
Reactive Power	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		6/30/2016	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).
Real Power	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007			The portion of electricity that supplies energy to the load.

Retired Terms							
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Reallocation	<a href="#">Version 0 Reliability Standards</a>		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 Assessment	<a href="#">Operate Within Interconnection Reliability Operating Limits</a>		10/17/2008	3/17/2011		12/31/2016	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Reliability Coordinator	<a href="#">Version 0 Reliability Standards</a>	RC	2/8/2005	3/16/2007		6/30/2007	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 Directive	<a href="#">Project 2006-06 Reliability Coordination</a>		8/16/2012	11/19/2015		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	<a href="#">Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions</a>		5/9/2013	7/9/2013		6/30/2016	A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
Reliable Operation	<a href="#">Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions</a>		5/9/2013	7/9/2013		6/30/2016	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.

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Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Remedial Action Scheme	<a href="#">Version 0 Reliability Standards</a>	RAS	2/8/2005	3/16/2007		3/31/2017	See "Special Protection System"
Reporting Ace			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). Reporting ACE is calculated as follows:                      Reporting ACE = <math>(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}</math>                      Reporting ACE is calculated in the Western Interconnection as follows:                      Reporting ACE = <math>(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}</math>                      Where:  <b>NI<sub>A</sub> (Actual Net Interchange)</b> 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.  <b>NI<sub>S</sub> (Scheduled Net Interchange)</b> 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 Interchange Actual.</p>
Reporting Ace (Continued)			8/15/2013	4/16/2015 (Will not go into effect)			<p><b>B (Frequency Bias Setting)</b> is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority.  <b>10</b> is the constant factor that converts the frequency bias setting units to MW/Hz.  <b>F<sub>A</sub> (Actual Frequency)</b> is the measured frequency in Hz.  <b>F<sub>S</sub> (Scheduled Frequency)</b> is 60.0 Hz, except during a time correction.  <b>I<sub>ME</sub> (Interchange Meter Error)</b> 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).  <b>I<sub>ATEC</sub> (Automatic Time Error Correction)</b> 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> <p>ATEC shall be zero when operating in Manual mode. When operating in Automatic Time Error Correction control mode:  <math display="block">I_{ATEC} = \frac{PI_{Inadvertent}}{(1-\gamma)^T H}</math>                      • Y = B / BS.                      • H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.</p>

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Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Reporting Ace (Continued)							<p>energy. The value of H is set to 3.</p> <p><math>B_S</math> = Frequency Bias for the Interconnection (MW / 0.1 Hz).</p> <ul style="list-style-type: none"> <li>Primary Inadvertent Interchange (<math>PII_{hourly}</math>) is <math>(1-Y) * (II_{actual} - B * \Delta TE/6)</math></li> <li><math>II_{actual}</math> is the hourly Inadvertent Interchange for the last hour.</li> <li><math>\Delta TE</math> is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where: <math>\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})</math></li> <li><math>TD_{adj}</math> is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks.</li> <li><math>t</math> is the number of minutes of Manual Time Error Correction that occurred during the hour.</li> <li><math>TE_{offset}</math> is 0.000 or +0.020 or -0.020.</li> <li><math>PII_{accum}</math> is the Balancing Authority's accumulated <math>PII_{hourly}</math> in MWh. An On-Peak and Off-Peak accumulation accounting is required.</li> </ul> <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</p>
Reporting Ace (Continued)			8/15/2013	4/16/2015 (Will not go into effect)			<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 Balancing Authorities on an interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard.</p> <ol style="list-style-type: none"> <li>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.</li> <li>The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times.</li> <li>The use of a common Scheduled Frequency FS for all areas at all times.</li> <li>The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)</li> </ol>
Request for Interchange	<a href="#">Coordinate Interchange</a>	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.
Reserve Sharing Group	<a href="#">Version 0 Reliability Standards</a>	RSG	2/8/2005	3/16/2007		6/30/2016	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.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Reserve Sharing Group Reporting ACE	<a href="#">Project 2010-14.1 Phase 1</a>		8/15/2013	4/16/2015		12/31/2017	At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Reserve Sharing Group at the time of measurement.
Resource Planner	<a href="#">Version 0 Reliability Standards</a>	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.
Right-of-Way	<a href="#">Project 2007-07</a>	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.
Right-of-Way	<a href="#">Project 2007-07</a>	ROW	11/3/2011	3/21/2013		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.
Sink Balancing Authority	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		9/30/2014	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.)
Source Balancing Authority	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		9/30/2014	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.)
Special Protection System (Remedial Action Scheme)	<a href="#">Version 0 Reliability Standards</a>	SPS	2/8/2005	3/16/2007 (Becomes inactive 3/31/2017)		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.

## Retired Terms

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
System Operating Limit	<a href="#">Version 0 Reliability Standards</a>	SOL	2/8/2005	3/16/2007		6/30/2014	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"> <li>• Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)</li> <li>• Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)</li> <li>• Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)</li> <li>• System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)</li> </ul>
System Operator	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007		6/30/2016	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.
Transmission Customer	<a href="#">Version 0 Reliability Standards</a>		2/8/2005	3/16/2007			1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Operator	<a href="#">Version 0 Reliability Standards</a>	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 Owner	<a href="#">Version 0 Reliability Standards</a>	TO	2/8/2005	3/16/2007			The entity that owns and maintains transmission facilities.
Transmission Planner	<a href="#">Version 0 Reliability Standards</a>	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 Service Provider	<a href="#">Version 0 Reliability Standards</a>	TSP	2/8/2005	3/16/2007			The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Vegetation Inspection	<a href="#">Transmission Vegetation</a>		2/7/2006	3/16/2007		3/20/2013	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection	<a href="#">Project 2007-07 Transmission Vegetation Management</a>		11/3/2011	3/21/2013		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.

NPCC REGIONAL DEFINITIONS							
NPCC Regional Term	Link to Implementation Plan	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Current Zero Time	<a href="#">PRC-002-NPCC-1 Implementation Plan</a>		11/4/2010	10/20/2011	10/20/2013		The time of the final current zero on the last phase to interrupt.
Generating Plant	<a href="#">PRC-002-NPCC-1 Implementation Plan</a>		11/4/2010	10/20/2011	10/20/2013		One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

RELIABILITYFIRST REGIONAL DEFINITIONS							
RELIABILITYFIRST Regional Term	Link to FERC Order	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Resource Adequacy	<a href="#">BAL-502-RFC-02 Implementation Plan</a>		8/5/2009	<a href="#">3/17/2011</a>			The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand	<a href="#">BAL-502-RFC-02 Implementation Plan</a>		8/5/2009	<a href="#">3/17/2011</a>			Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period	<a href="#">BAL-502-RFC-02 Implementation Plan</a>		8/5/2009	<a href="#">3/17/2011</a>			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	<a href="#">BAL-502-RFC-02 Implementation Plan</a>		11/3/2011 (Board withdrew approval 11/7/2012)	<a href="#">3/17/2011</a>			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	<a href="#">BAL-502-RFC-02 Implementation Plan</a>		8/5/2009	<a href="#">3/17/2011</a>			The planning year that begins with the upcoming annual Peak Period

TEXAS RE REGIONAL DEFINITIONS						
Frequency Measurable Event	<a href="#">BAL-001-TRE-1 Implementation Plan</a>	FME	8/15/2013	1/16/2014	4/1/2014	An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions:  i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year).  Or  ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).
Governor			8/15/2013	1/16/2014	4/1/2014	The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.
Primary Frequency Response	<a href="#">BAL-001-TRE-1 Implementation Plan</a>	PFR	8/15/2013	1/16/2014	4/1/2014	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.

WECC REGIONAL DEFINITIONS							
WECC Regional Term	WECC Standards Under Development	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
<a href="#">Area Control Error *</a>	<a href="#">WECC Regional Standards Under Development</a>	ACE	3/12/2007	6/8/2007		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.
<a href="#">Automatic Generation Control *</a>	<a href="#">WECC Regional Standards Under Development</a>	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	<a href="#">WECC Regional Standards Under Development</a>		3/26/2008	5/21/2009		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	<a href="#">WECC Regional Standards Under Development</a>		12/19/2012	10/16/2013	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.

<a href="#">Average Generation *</a>	<a href="#">WECC Regional Standards Under Development</a>		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).
<a href="#">Business Day *</a>	<a href="#">WECC Regional Standards Under Development</a>		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.
Commercial Operation	<a href="#">WECC Regional Standards Under Development</a>		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	<a href="#">WECC Regional Standards Under Development</a>		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	<a href="#">WECC Regional Standards Under Development</a>		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 <b>certainty to operate when required</b> .
<a href="#">Disturbance *</a>	<a href="#">WECC Regional Standards Under Development</a>		3/12/2007	6/8/2007		Retired	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.
<a href="#">Extraordinary Contingency†</a>	<a href="#">WECC Regional Standards Under Development</a>		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>

WECC REGIONAL DEFINITIONS							
WECC Regional Term	WECC Standards Under Development	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
<a href="#">Frequency Bias *</a>	<a href="#">WECC Regional Standards Under Development</a>		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	<a href="#">WECC Regional Standards Under Development</a>	FEPS	10/29/2008	4/21/2011		<p>A Protection System that provides performance as follows:</p> <ul style="list-style-type: none"> <li>• 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.</li> <li>• Each Protection System may have different components and operating characteristics.</li> </ul>
Functionally Equivalent RAS	<a href="#">WECC Regional Standards Under Development</a>	FERAS	10/29/2008	4/21/2011		<p>A Remedial Action Scheme (“RAS”) that provides the same performance as follows:</p> <ul style="list-style-type: none"> <li>• Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards.</li> <li>• Each RAS may have different components and operating characteristics.</li> </ul>
<a href="#">Generating Unit Capability *</a>	<a href="#">WECC Regional Standards Under Development</a>		3/12/2007	6/8/2007		Means the MVA nameplate rating of a generator.
<a href="#">Non-spinning Reserve†</a>	<a href="#">WECC Regional Standards Under Development</a>		3/12/2007	6/8/2007	Retired	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.
<a href="#">Normal Path Rating *</a>	<a href="#">WECC Regional Standards Under Development</a>		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.
<a href="#">Operating Reserve *</a>	<a href="#">WECC Regional Standards Under Development</a>		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.
<a href="#">Operating Transfer Capability Limit *</a>	<a href="#">WECC Regional Standards Under Development</a>	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.
Primary Inadvertent Interchange	<a href="#">WECC Regional Standards Under Development</a>		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	<a href="#">WECC Regional Standards Under Development</a>		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	<a href="#">WECC Regional Standards Under Development</a>		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	<a href="#">WECC Regional Standards Under Development</a>		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.

WECC Regional Term	WECC Standards Under Development	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Relief Requirement	<a href="#">WECC Regional Standards Under Development</a>		2/10/2009	3/17/2011		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	<a href="#">WECC Regional Standards Under Development</a>		2/7/2013	6/13/2014	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 Interchange	<a href="#">WECC Regional Standards Under Development</a>		3/26/2008	5/21/2009			The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Security-Based Misoperation	<a href="#">WECC Regional Standards Under Development</a>		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.
<a href="#">Spinning Reserve†</a>	<a href="#">WECC Regional Standards Under Development</a>		3/12/2007	6/8/2007		Retired	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	<a href="#">WECC Regional Standards Under Development</a>	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).]
<a href="#">WECC Table 2 *</a>	<a href="#">WECC Regional Standards Under Development</a>		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
7/3/2018	Updated effective date for Operational Planning Analysis (OPA), Protections System Coordination Study and Real-time Assessment (RTA).
6/12/2018	Added revised definitions of Transient Cyber Asset and Removable Media to the Pending Enforcement tab.
1/31/2018	Fixed truncated definition for Texas RE term Primary Frequency Response
1/2/2018	<b>Moved to Subject to Enforcement:</b> Balancing Contingency Event; Contingency Event Recovery Period; Contingency Reserve; Contingency Reserve Restoration Period; Most Severe Single Contingency; Pre-Reporting Contingency Event ACE Value; Reportable Balancing Contingency Event; Reserve Sharing Group Reporting ACE <b>Moved to Retired tab:</b> Contingency Reserve; Reserve Sharing Group Reporting ACE
10/6/2017	Added the Effective date of Automatic Generation Control, Pseudo-Tie and Balancing Authority
8/1/2017	Moved to Subject to Enforcement: Reporting Ace, Actual Frequency, Actual Net Interchange, Schedule Net Interchange, Interchange Meter Error, Automatic Time Error Correction
7/24/2017	Updated project link for definitions related to Project 2014-02, board adopted 2/12/15.
7/14/2017	Updated project link to Remedial Action Scheme with an effective date of 4/1/17; Removeable Media link to project 2014-02.
7/3/2017	Moved 'Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment' to Subject to Enforcement
6/15/2017	Readded 'Governor' and 'Primary Frequency Response' to TexasRE
4/4/2017	Moved to Subject to Enforcement: Energy Emergency, Remedial Action Scheme, Special Protection System and Under3 Voltage Load Shedding Program. Moved terms inactive 3/31/17 to Retired tab.
3/16/2017	Removed Pending Inactive tab; not necessary
3/10/2017	Added <b>Pending Inactive</b> tab
2/7/2017	<b>Added Effective Dates for:</b> Balancing Contingency Event, Most Severe Single Contingency (MSSC), Reportable Balancing Contingency Event, Contingency Event Recovery Period, Contingency Reserve Restoration Period, Pre-Reporting Contingency Event ACE Value, Reserve Sharing Group Reporting ACE, Contingency Reserve
1/25/2017	Removed WECC terms 'Non-Spinning Reserve' and 'Spinning Reserve' per FERC Order No. 789. Docket No. RM13-13-000.
1/6/2017	Moved the following terms from Pending Enforcement to Subject to Enforcement: Operational Planning Analysis, Real-time Assessment (Revised Definition)
1/5/2017	<b>Formatting of Glossary of Terms updated.</b>
12/12/16	<b>Updated:</b> 'Adverse Reliability Impact' from Pending to Retired. NERC withdrew the related petition 3/18/2015
11/28/16	<b>Updated</b> ReliabilityFirst - Wind Generating Station term to inactive
9/28/16	<b>Updated</b> CIP v 5 standards effective date from 4/1/2016 to 7/1/2016 per FERC Order 822.
8/17/16	<b>Board Adopted:</b> Operational Planning Analysis and Real-time Assessment
7/13/16	Updated color coding of terms retired 6/30/2016 based on the terms becoming effective 7/1/2016.
6/24/16	<b>FERC approved:</b> Actual Frequency, Actual Net Interchange, Scheduled Net Interchange (NIS), Interchange Meter Error (IME), and Automatic Time Error Correction (ATEC)
	Reporting ACE: status updated

6/21/16	<b>Correction:</b> Reserve Sharing Group Reporting ACE, and Contingency Reserve changed to 11/5/2015 Board adoption date status
4/1/16	<b>Effective:</b> 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
3/31/16	<b>Inactive:</b> Critical Assets, Critical Cyber Assets, Cyber Assets, Cyber Security Incident, Electronic Security Perimeter, Physical Security Perimeter