NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

April 12, 2007

VIA OVERNIGHT MAIL

Kirsten Walli, Board Secretary
Ontario Energy Board
P.O Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

Re: *North American Electric Reliability Corporation*

Dear Ms. Walli:

The North American Electric Reliability Corporation ("NERC") hereby submits a Notice of Additional Amendment to Application for Recognition of Proposed Reliability Standards for Approval of Violation Risk Factors for Version 0 and Version 1 Reliability Standards. In addition to the paper copy of this filing, NERC is also submitting one CD containing a copy of the filing. NERC requests, to the extent necessary, a waiver of any applicable filing requirements with respect to the filing of this notice.

Please contact the undersigned if you have any questions.

Respectfully submitted,

___/s/ Rick Sergel_____
Richard P. Sergel
President and Chief Executive Officer
David N. Cook
Vice President and General Counsel

North American Electric Reliability Corp.
116-390 Village Boulevard
Princeton, NJ 08540-5731
(609) 452-8060
(609) 452-9550 – facsimile
rick.sergel@nerc.net
david.cook@nerc.net

Enclosures

BEFORE THE
ONTARIO ENERGY BOARD
OF THE PROVINCE OF ONTARIO

NORTH AMERICAN ELECTRIC	**)**
RELIABILITY COUNCIL and	**)**
NORTH AMERICAN ELECTRIC	**)**
RELIABILITY CORPORATION	**)**

NOTICE OF ADDITIONAL AMENDMENT TO APPLICATION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR RECOGNITION OF PROPOSED RELIABILITY STANDARDS FOR APPROVAL OF VIOLATION RISK FACTORS FOR VERSION 0 AND VERSION 1 RELIABILITY STANDARDS

Richard P. Sergel
President and Chief Executive Officer
David N. Cook
Vice President and General Counsel
North American Electric Reliability Council
116-390 Village Boulevard
Princeton, NJ 08540-5731
(609) 452-8060
(609) 452-9550 – facsimile
rick.sergel@nerc.net
david.cook@nerc.net

April 12, 2007

TABLE OF CONTENTS

I.	INTRODUCTION	1
II.	NOTICES AND COMMUNICATIONS	2
III.	BACKGROUND ON DEVELOPMENT OF VIOLATION RISK FACTORS	2
IV.	OVERVIEW OF THE PROPOSED VIOLATION RISK FACTORS	6
	Table 1	8
	Table 2	9
V.	CONCLUSION	11

EXHIBIT A – PROPOSED VIOLATION RISK FACTORS FOR VERSION 0 RELIABILITY STANDARDS

EXHIBIT B – PROPOSED VIOLATION RISK FACTORS FOR VERSION 1 RELIABILITY STANDARDS

EXHIBIT C – RECORD OF DEVELOPMENT (Available Upon Request)

EXHIBIT D – STANDARDS DRAFTING TEAM ROSTER

I. <u>INTRODUCTION</u>

The North American Electric Reliability Corporation ("NERC") hereby submits for approval the proposed violation risk factors for the associated requirements in the Version 0 and Version 1 reliability standards. The Version 0 and Version 1 reliability standards are the initial set of standards NERC submitted for approval on April 4, 2006 and the reliability standards submitted in subsequent amendments to that filing. With the exceptions noted below, this filing represents the complete set of proposed violation risk factors for all reliability standards submitted for approval.

A violation risk factor has been assigned to each requirement in NERC's proposed Version 0 and Version 1 reliability standards to delineate the relative risk to the bulk power system associated with the violation of each requirement. The violation risk factors alone do not change the meaning or intent of the standards. The violations risk factors will be used by NERC and the regional entities in determining financial penalties for violating the standards, in those jurisdictions where NERC is authorized to impose financial penalties, as described in Section 4 of the *ERO Sanction Guidelines*, Appendix 4B to the NERC Rules of Procedure.

NERC has not yet developed violation risk factors for any of the requirements for FAC-003-1 or for one requirement each in COM-002-2 and PRC-005-1, as detailed further in Section III of this filing. NERC commits to developing these violation risk factors for filing shortly after the NERC Board's May 2, 2007 meeting. *See* Section III of this filing, below.

Tables 1 and 2 below list the reliability standards for which violation risk factors are being submitted in this filing. **Exhibits A and B** to this filing present the violation risk factors that have been assigned to each requirement in the relevant reliability standards. **Exhibit C** (available upon request due to its volume) presents the record of development of the violation risk factors. **Exhibit D** provides the roster of the drafting team that developed, with the stakeholders, the violation risk factors.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

Rick Sergel
President and Chief Executive Officer
David N. Cook
Vice President and General Counsel
North American Electric Reliability
Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
rick.sergel@nerc.net
david.cook@nerc.net

III. BACKGROUND ON DEVELOPMENT OF VIOLATION RISK FACTORS

The concept of the violation risk factors was originally envisioned by the NERC Board of Trustees several years ago as a way to rank the relative importance of standards violations. In 2004, the NERC Compliance and Certification Committee implemented a reporting process that included a plan to refine the descriptions of violations that were to be reported to the NERC Board of Trustees and determine if the violations were significant. In February 2005, the Board asked the NERC Compliance and Certification Committee and the Compliance and Certification Managers Committee to complete the process for classifying compliance violations, so that the Board and the public could better understand the significance of each violation.

In October 2005, the NERC Standards Committee and the Compliance and Certification Committee agreed to a set of definitions and to an approach to develop the violation risk factors within the standards development process. In January 2006, the Enforcement, Sanctions, and

Disclosure Subcommittee of the Compliance and Certification Committee submitted a standards authorization request ("SAR") to develop the risk factors. The SAR is the foundational document used in the NERC standards development process to request a new standard or the revision of an existing standard. The SAR and a preliminary list of violation risk factors for the Version 0 reliability standards were posted for public comment in February 2006. Once the SAR was authorized by the Standards Committee for development, the drafting team surveyed the industry twice to gather input and feedback on the proposed violation risk factors. The initial survey was conducted from April 2006 to June 2006, and the second survey was conducted from July 2006 to August 2006. The drafting team made adjustments to the Version 0 violation risk factors to reflect the consensus of the industry.

As the violation risk factors were being developed, NERC proposed in its application for recognition as the ERO (filed April 4, 2006) that the violation risk factors should be used for compliance enforcement as an initial element in the setting of financial penalties, as described in the *ERO Sanction Guidelines* submitted with that filing.

Subsequently, the Standards Committee tasked the violation risk factor drafting team with adding violation risk factors to all new and revised reliability standards that the team anticipated would be completed and filed through November 2006, to ensure that all standards approved for implementation by June 2007 would have associated violation risk factors. The resulting violation risk factors for the Version 1 reliability standards were subject to a single round of public comment from July 2006 to August 2006. While the Version 1 violation risk factors were posted for public comment, the violation risk factors for the Version 0 standards underwent a second survey during the same timeframe.

The combined table of Version 0 and Version 1 violation risk factors was then put to a vote of stakeholders from October 6 to October 16, 2006. The weighted average vote of the ballot pool was 54% in the affirmative, which fell short of the required two-thirds weighted average affirmative vote required for approval.[1] Therefore, the ballot was terminated and the violation risk factors were not approved. However, stakeholder comments received during the ballot had revealed a strong desire to separate the Version 0 and Version 1 risk factors, to allow a second round of public comment, and to further subdivide the Version 0 risk factors into related "family" groupings of standards for balloting purposes.

As a result, the Version 0 violation risk factors were divided into nine family groups of related reliability standards. The Version 0 violation risk factors were then balloted from December 4 to December 5, 2006, and, after careful consideration of comments from the initial ballot, re-balloted from February 2 to February 11, 2007. The second ballot resulted in stakeholder approval of the Version 0 violation risk factors. The Version 0 violation risk factors were approved by the NERC Board of Trustees February 13, 2007.

The standards groupings and the results of the final stakeholder ballot for the violation risk factors for the Version 0 reliability standards were as follows:

1. Balance and Interchange — 88.45% voting; affirmative weighted segment vote, 77.81%
2. Communication and Facilities — 87.36% voting; affirmative weighted segment vote, 78.97%
3. Emergency Operations — 88.13% voting; affirmative weighted segment vote, 72.70%
4. Interconnection Reliability Operations — 87.73% voting; affirmative weighted segment vote, 80.44%

[1] Under the NERC Reliability Standards Development Procedure, approval of a new or revised reliability standard requires a quorum of 75% of the members of the registered ballot pool for the proposed standard, and a two-thirds affirmative majority of the weighted segment votes cast. The number of votes cast is the sum of the affirmative and negative votes, excluding abstentions and non-responses.

5. Modeling — 88.41% voting; affirmative weighted segment vote, 87.70%
6. Personnel — 87.41% voting; affirmative weighted segment vote, 70.13%
7. Protection & Control — 87.32% voting; affirmative weighted segment vote, 75.14%
8. Transmission Operations and Voltage Control — 87.77% voting; affirmative weighted segment vote 82.34%
9. Transmission Planning — 88.13% voting; affirmative weighted segment vote, 76.61%.

A second round of public comment was conducted on the Version 1 violation risk factors from November 2 to December 1, 2006. After incorporation of comments, an initial ballot for the seven groups of Version 1 risk factors was held from February 14 to February 23, 2007. A second ballot was held from February 28 to March 9, 2007. The balloting resulted in approval of all the violation risk factors for the Version 1 reliability standards. The results of the final stakeholder ballot for the violation risk factors for the Version 1 reliability standards were as follows:

Version 1 Violation Risk Factor Group	Quorum Percentage	Weighted Segment Vote
Critical Infrastructure Protection	83%	88%
Facility Ratings	85%	86%
Balancing and Interchange	84%	94%
Interconnection Reliability Operations	82%	86%
Modeling	84%	90%
Protection & Control	85%	93%
Emergency Operations, Voltage Control, and Transmission Operations	83%	86%

The NERC board approved the Version 1 violation risk factors on March 12, 2007.

Each violation risk factor assignment will be included for review as part of NERC's required five-year review of each reliability standard, or is already included in NERC's three-year standards development work plan.[2]

[2] *See* Informational Filing on the North American Electric Reliability Council's and North American Electric Reliability Corporation's Reliability Standards Development Plan: 2007—2009, submitted on December 5, 2006.

As it prepared this filing, NERC performed a comprehensive review of its reliability standards pending for approval to identify any omissions in violation risk factor assignment. Upon review of the nearly 1,300 requirements included in the standards submitted for approval, NERC identified six individual requirements without an assigned violation risk factor:

- COM-002-2 Requirement R2
- FAC-010-1 Requirement R2.3.2
- FAC-014-1 Requirement R6.2
- PRC-003-1 Requirement R3
- PRC-005-1 Requirement R2.1
- PRC-014-0 Requirement R3.5

In addition, NERC identified that reliability standards PRC-020-1 and FAC-003-1 did not have violation risk factors assigned for any requirements. Of these eight reliability standards, COM-002-2, PRC-005-1 and FAC-003-1 are included in the reliability standards the Federal Energy Regulatory Commission ("FERC") approved in Order No. 693.[3] To ensure NERC is prepared to enforce mandatory compliance with these reliability standards beginning in June 2007 in the United States, NERC will employ its urgent action standards development process to assign violation risk factors to these standard requirements and will file the resulting violation risk factors shortly after the NERC Board's May 2, 2007 meeting.[4]

IV. OVERVIEW OF THE PROPOSED VIOLATION RISK FACTORS

Section 4.1.1 of the *ERO Sanction Guidelines* states that NERC will assign a risk factor of "high", "medium", or "lower" to each requirement in a NERC reliability standard. In

[3] FERC issued a final rule approving 83 of the proposed 107 standards on March 16, 2007. FERC directed that the remaining 24 Reliability Standards will remain pending at the Commission until further information is provided. The final rule will go into effect in the United States on June 4, 2007.

[4] NERC's Standards Committee has authorized the urgent action process for the assignment of the required violation risk factors, and NERC has posted the proposed violation risk factors for a 30-day pre-ballot review.

accordance with this provision, the violation risk factors associated with reliability standards requirements are placed into one of the following three risk categories:

- **High Risk Requirement —** (a) Is a requirement that, if violated, could directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures; or (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

- **Medium Risk Requirement —** (a) Is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures; or (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk power system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

- **Lower Risk Requirement —** Is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.

Violation risk factors represent one element that will be used by NERC and regional entities to determine monetary and non-monetary penalties, in those jurisdictions where NERC or Regional Entities have the authority, when a requirement of a reliability standard has been violated. Violation severity levels – lower, moderate, high, and severe – measure the degree to which a requirement was violated. The violation risk factors, coupled with violation severity levels, set the range for the base penalty amount for a violation of a specific requirement.[5] The violation risk factors represent a key element of the NERC reliability standards and the compliance and enforcement process. The violation risk factors are a determinant of the base range of penalties for violations of requirements in reliability standards, in accordance with the NERC Rules of Procedure.

Tables 1 and 2 below list, respectively, the Version 0 and Version 1 reliability standards NERC has submitted for approval for which violation risk factors are submitted in this filing.

Table 1 — Version 0 Violation Risk Factor Submission – Affected Standards

Number	Title
BAL-001-0	Real Power Balancing Control Performance
BAL-002-0	Disturbance Control Performance
BAL-003-0	Frequency Response and Bias

[5] Appendix A of the *ERO Sanction Guidelines* provides a table illustrating the use of violation risk factors in determining penalties.

Number	Title
BAL-004-0	Time Error Correction
BAL-005-0	Automatic Generation Control
CIP-001-0	Sabotage Reporting
COM-001-0	Telecommunications
COM-002-0	Communications and Coordination
EOP-001-0	Emergency Operations Planning
EOP-002-0	Capacity and Energy Emergencies
EOP-003-0	Load Shedding Plans
EOP-004-0	Disturbance Reporting
EOP-005-0	System Restoration Plans
EOP-006-0	Reliability Coordination - System Restoration
EOP-007-0	Establish, Maintain, and Document a Regional Blackstart Capability Plan
EOP-008-0	Plans for Loss of Control Center Functionality
EOP-009-0	Documentation of Blackstart Generating Unit Test Results
FAC-001-0	Facility Connection Requirements
FAC-002-0	Coordination of Plans for New Facilities
FAC-003-0	Vegetation Management Program
FAC-004-0	Methodologies for Determining Electrical Facility Ratings
FAC-005-0	Electrical Facility Ratings for System Modeling
INT-001-0	Interchange Transaction Tagging
INT-002-0	Interchange Transaction Tag Communication and Assessment
INT-003-0	Interchange Transaction Implementation
INT-004-0	Interchange Transaction Modifications
IRO-001-0	Reliability Coordination – Responsibilities and Authorities
IRO-002-0	Reliability Coordination – Facilities
IRO-003-0	Reliability Coordination – Wide Area View
IRO-004-0	Reliability Coordination – Operations Planning
IRO-005-0	Reliability Coordination – Current Day Operations
IRO-006-0	Reliability Coordination – Transmission Loading Relief
MOD-001-0	Documentation of TTC and ATC Calculation Methodologies
MOD-002-0	Review of TTC and ATC Calculations and Results
MOD-003-0	Procedure for Input on TTC and ATC Methodologies and Values
MOD-004-0	Documentation of Regional CBM Methodologies
MOD-005-0	Procedure for Verifying CBM Values
MOD-006-0	Procedures for Use of CBM Values
MOD-007-0	Documentation of the Use of CBM
MOD-008-0	Documentation and Content of Each Regional TRM Methodology
MOD-009-0	Procedure for Verifying TRM Values
MOD-010-0	Steady-State Data for Transmission System Modeling and Simulation
MOD-011-0	Regional Steady-State Data Requirements and Reporting Procedures

Number	Title
MOD-012-0	Dynamics Data for Transmission System Modeling and Simulation
MOD-013-0	RRO Dynamics Data Requirements and Reporting Procedures
MOD-014-0	Development of Interconnection-Specific Steady State System Models
MOD-015-0	Development of Interconnection-Specific Dynamics System Models
MOD-016-0	Actual and Forecast Demands, Net Energy for Load, Controllable DSM
MOD-017-0	Aggregated Actual and Forecast Demands and Net Energy for Load
MOD-018-0	Reports of Actual and Forecast Demand Data
PER-003-0	Operating Personnel Credentials
PER-004-0	Reliability Coordination – Staffing
PRC-001-0	System Protection Coordination
PRC-002-0	Define and Document Disturbance Monitoring Equipment Requirements
PRC-003-0	Regional Procedure for Transmission Protection System Misoperations
PRC-004-0	Analysis and Reporting of Transmission Protection System Misoperations
PRC-005-0	Transmission Protection System Maintenance and Testing
PRC-006-0	Development and Documentation of Regional UFLS Programs
PRC-007-0	Assuring Consistency with Regional UFLS Program Requirements
PRC-008-0	Underfrequency Load Shedding Equipment Maintenance Programs
PRC-009-0	UFLS Performance Following an Underfrequency Event
PRC-010-0	Assessment of the Design and Effectiveness of UVLS Program
PRC-011-0	UVLS System Maintenance and Testing
PRC-012-0	Special Protection System Review Procedure
PRC-013-0	Special Protection System Database
PRC-014-0	Special Protection System Assessment
PRC-015-0	Special Protection System Data and Documentation
PRC-016-0	Special Protection System Misoperations
PRC-017-0	Special Protection System Maintenance and Testing
TOP-001-0	Reliability Responsibilities and Authorities
TOP-002-0	Normal Operations Planning
TOP-004-0	Transmission Operations
TOP-005-0	Operational Reliability Information
TOP-006-0	Monitoring System Conditions
TOP-007-0	Reporting SOL and IROL Violations
TOP-008-0	Response to Transmission Limit Violations
TPL-001-0	System Performance Under Normal Conditions
TPL-002-0	System Performance Following Loss of a Single BES Element
TPL-003-0	System Performance Following Loss of Two or More BES Elements
TPL-004-0	System Performance Following Extreme BES Events
TPL-005-0	Regional and Interregional Self-Assessment Reliability Reports
TPL-006-0	Assessment Data from Regional Reliability Organizations
VAR-001-0	Voltage and Reactive Control

Table 2 — Version 1 Violation Risk Factor Submission – Affected Standards

Number	Title
BAL-006-1	Inadvertent Interchange
CIP-002-1	Critical Cyber Asset Identification
CIP-003-1	Security Management Controls
CIP-004-1	Personnel and Training
CIP-005-1	Electronic Security Perimeters
CIP-006-1	Physical Security of Critical Cyber Assets
CIP-007-1	Systems Security Management
CIP-008-1	Incident Reporting and Response Planning
CIP-009-1	Recovery Plans for Critical Cyber Assets
EOP-005-1	System Restoration Plans
FAC-008-1	Facility Ratings Methodology
FAC-009-1	Establish and Communicate Facility Ratings
FAC-010-1	System Operating Limits Methodology for the Planning Horizon
FAC-011-1	System Operating Limits Methodology for the Operations Horizon
FAC-012-1	Transfer Capability Methodology
FAC-013-1	Establish and Communicate Transfer Capabilities
FAC-014-1	Establish and Communicate System Operating Limits
INT-001-2	Interchange Information
INT-003-2	Interchange Transaction Implementation
INT-004-1	Dynamic Interchange Transaction Modifications
INT-005-1	Interchange Authority Distributes Arranged Interchange
INT-006-1	Response to Interchange Authority
INT-007-1	Interchange Confirmation
INT-008-1	Interchange Authority Distributes Status
INT-009-1	Implementation of Interchange
INT-010-1	Interchange Coordination Exceptions
IRO-014-1	Procedures, Processes or Plans to Support Coordination Between Reliability Coordinators
IRO-015-1	Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1	Coordination of Real-time Activities Between Reliability Coordinators
MOD-013-1	Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures
MOD-016-1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable DSM
MOD-024-1	Verification of Generator Gross and Net Real Power Capability
MOD-025-1	Verification of Generator Gross and Net Reactive Power Capability
PRC-002-1	Define and Document Disturbance Monitoring Equipment Requirements

Number	Title
PRC-018-1	Disturbance Monitoring Equipment Installation and Data Reporting
PRC-021-1	Under-Voltage Load Shedding Program Data
PRC-022-1	Under-Voltage Load Shedding Program Performance
TOP-002-2	Normal Operations Planning
VAR-001-1	Voltage and Reactive Control
VAR-002-1	Generator Operation for Maintaining Network Voltage Schedules

V. CONCLUSION

NERC respectfully requests approval of the proposed violation risk factors for the Version 0 and Version 1 reliability standards that are being submitted with this filing.

Respectfully submitted,

/s/ Rick Sergel______________________
President and Chief Executive Officer
David N. Cook
Vice President and General Counsel
North American Electric Reliability Council
116-390 Village Boulevard
Princeton, NJ 08540-5731
(609) 452-8060
(609) 452-9550 – facsimile
rick.sergel@nerc.net
david.cook@nerc.net

Exhibit A

Proposed Violation Risk Factors for Version 0 Reliability Standards

The following table lists the Violation Risk Factors (VRFs) for the Version 0 Resource and Demand Balancing and Interchange Scheduling and Coordination standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
BAL-001-0	R1.	Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee. See Standard for Formula.	LOWER
BAL-001-0	R2.	Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L10. See Standard for Formula.	LOWER
BAL-001-0	R3.	Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.	LOWER
BAL-001-0	R4.	Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).	LOWER
BAL-002-0	R1.	Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.	HIGH
BAL-002-0	R1.1.	A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL002.	LOWER
BAL-002-0	R2.	Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:	LOWER
BAL-002-0	R2.1.	The minimum reserve requirement for the group.	LOWER
BAL-002-0	R2.2.	Its allocation among members.	LOWER
BAL-002-0	R2.3.	The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.	LOWER
BAL-002-0	R2.4.	The procedure for applying Contingency Reserve in practice.	LOWER
BAL-002-0	R2.5.	The limitations, if any, upon the amount of interruptible load that may be included.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
BAL-002-0	R2.6.	The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.	MEDIUM
BAL-002-0	R3.	Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.	HIGH
BAL-002-0	R3.1.	As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	LOWER
BAL-002-0	R4.	A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	LOWER
BAL-002-0	R4.1.	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.	MEDIUM
BAL-002-0	R4.2.	The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.	LOWER
BAL-002-0	R5.	Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:	LOWER
BAL-002-0	R5.1.	The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.	LOWER
BAL-002-0	R5.2.	The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.	LOWER
BAL-002-0	R6.	A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.	MEDIUM
BAL-002-0	R6.1.	The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	LOWER
BAL-002-0	R6.2.	The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
BAL-003-0	R1.	Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.	LOWER
BAL-003-0	R1.1.	The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.	LOWER
BAL-003-0	R1.2.	Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.	LOWER
BAL-003-0	R2.	Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:	LOWER
BAL-003-0	R2.1.	The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.	LOWER
BAL-003-0	R2.2.	The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.	LOWER
BAL-003-0	R3.	Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.	LOWER
BAL-003-0	R4.	Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.	LOWER
BAL-003-0	R4.1.	Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.	LOWER
BAL-003-0	R4.2.	The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting. See Standard for Graphic	LOWER
BAL-003-0	R5.	Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.	LOWER
BAL-003-0	R5.1.	Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.	LOWER
BAL-003-0	R6.	A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
BAL-004-0	R1.	Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.	LOWER
BAL-004-0	R2.	The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.	LOWER
BAL-004-0	R3.	Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:	LOWER
BAL-004-0	R3.1.	The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or	LOWER
BAL-004-0	R3.2.	The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).	LOWER
BAL-004-0	R4.	Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.	LOWER
BAL-004-0	R4.1.	Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.	LOWER
BAL-005-0	R1.	All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.	MEDIUM
BAL-005-0	R1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.	LOWER
BAL-005-0	R1.2.	Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.	LOWER
BAL-005-0	R1.3.	Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.	LOWER
BAL-005-0	R2.	Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.	LOWER
BAL-005-0	R3.	A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.	MEDIUM
BAL-005-0	R4.	A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.	MEDIUM
BAL-005-0	R5.	A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
BAL-005-0	R6.	The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.	MEDIUM
BAL-005-0	R7.	The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.	LOWER
BAL-005-0	R8.	The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.	MEDIUM
BAL-005-0	R8.1.	Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.	MEDIUM
BAL-005-0	R9.	The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.	LOWER
BAL-005-0	R9.1.	Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.	LOWER
BAL-005-0	R10.	The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.	HIGH
BAL-005-0	R11.	Balancing Authorities shall include the effect of Ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.	MEDIUM
BAL-005-0	R12.	Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.	MEDIUM
BAL-005-0	R12.1.	Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.	LOWER
BAL-005-0	R12.2.	Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.	MEDIUM
BAL-005-0	R12.3.	Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
BAL-005-0	R13.	Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.	LOWER
BAL-005-0	R14.	The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.	LOWER
BAL-005-0	R15.	The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.	LOWER
BAL-005-0	R16.	The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.	MEDIUM
BAL-005-0	R17.	Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below: See Standard for Values	LOWER
INT-001-0	R1.	The load-serving Purchasing-Selling Entity shall be responsible for ensuring Tags are submitted for:	MEDIUM
INT-001-0	R1.1.	All Interchange Transactions that are between Balancing Authority Areas	MEDIUM
INT-001-0	R1.2.	All transfers that are entirely within a Balancing Authority Area using Point-to-Point Transmission Service (including all grandfathered and "non-Order 888" Point-to-Point Transmission service).	MEDIUM
INT-001-0	R1.3.	All Dynamic Schedules at the expected average MW profile for each hour.	MEDIUM
INT-001-0	R2.	The Sink Balancing Authority shall be responsible for ensuring a tag is provided:	MEDIUM
INT-001-0	R2.1.	If a Purchasing-Selling Entity is not involved in the Transaction, such as delivery from a jointly owned generator.	MEDIUM
INT-001-0	R2.2.	To replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements. If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from tagging.	MEDIUM
INT-001-0	R2.3.	All Bilateral Inadvertent Interchange Payback.	MEDIUM
INT-001-0	R3.	The Purchasing Selling Entity responsible for submitting the Tag shall submit all Tags to the Sink Balancing Authority	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		according to timing tables in Attachment 1-INT-001-0.	
INT-001-0	R4.	The Balancing Authority or Purchasing-Selling Entity responsible for submitting the Tag shall include the reliability data listed in Attachment 2-INT-001-0 in the Tag.	MEDIUM
INT-001-0	R5.	Each Purchasing-Selling Entity with title to an Interchange Transaction shall have, or shall arrange to have, personnel directly and immediately available for notification of Interchange Transaction changes. These personnel shall be available from the time that the title to the Interchange Transaction is acquired until the Interchange Transaction has been completed.	MEDIUM
INT-002-0	R1.	The Sink Balancing Authority shall ensure that all Tags and any modifications to Tags are provided via a secure network to the following entities on the Scheduling Path:	MEDIUM
INT-002-0	R1.1.	Sink and Source Balancing Authority for the Transaction.	MEDIUM
INT-002-0	R1.2.	Intermediate Balancing Authorities on the Schedule Path.	MEDIUM
INT-002-0	R1.3.	Transmission Service Provider(s) on the Schedule Path.	MEDIUM
INT-002-0	R1.4.	Reliability analysis services (IDC or other regional reliability tools).	MEDIUM
INT-002-0	R1.5.	Transmission Operators and Reliability Coordinators who may receive the information through Reliability analysis services.	MEDIUM
INT-002-0	R2.	Transmission Service Providers on the Scheduling Path shall be responsible for assessing and approving or denying the Interchange Transaction based on established reliability criteria and adequacy of Interconnected Operating Services and transmission rights as well as the reasonableness of the Interchange Transaction Tag. The Transmission Service Provider shall verify and assess:	MEDIUM
INT-002-0	R2.1.	Valid OASIS reservation number or transmission contract identifier.	MEDIUM
INT-002-0	R2.2.	Transmission priority matches reservation.	MEDIUM
INT-002-0	R2.3.	Energy profile fits within OASIS reservation.	MEDIUM
INT-002-0	R2.4.	OASIS reservation accommodates all Interchange Transactions.	MEDIUM
INT-002-0	R2.5.	Connectivity of adjacent Transmission Service Providers.	MEDIUM
INT-002-0	R2.6.	Loss accounting.	MEDIUM
INT-002-0	R3.	Balancing Authorities on the Scheduling Path shall be responsible for assessing and approving or denying the Interchange Transaction. The Balancing Authority shall verify and assess:	MEDIUM
INT-002-0	R3.1.	Transaction start and end time.	MEDIUM
INT-002-0	R3.2.	Energy profile (ability to support the magnitude of the transaction).	MEDIUM
INT-002-0	R3.3.	Ramp (ability of generation maneuverability to accommodate).	MEDIUM
INT-002-0	R3.4.	Scheduling path (proper connectivity of adjacent Balancing Authorities).	MEDIUM
INT-002-0	R4.	Each Balancing Authority and Transmission Service Provider on the Scheduling Path shall communicate their approval or denial of the Interchange Transaction to the Sink Balancing Authority.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
INT-002-0	R5.	Upon receipt of approvals or denials from all of the individual Balancing Authorities and Transmission Service Providers, the Sink Balancing Authority shall communicate the composite approval status of the Interchange Transaction to the Purchasing-Selling Entity and all other Balancing Authorities and Transmission Service Providers on the Scheduling Path and through the Reliability analysis service to affected Transmission Operators and Reliability Coordinators.	MEDIUM
INT-003-0	R1.	Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.	MEDIUM
INT-003-0	R1.1.	The Sending Balancing Authority and Receiving Balancing Authority shall agree on:	MEDIUM
INT-003-0	R1.1.1.	Interchange Schedule start and end time.	MEDIUM
INT-003-0	R1.1.2.	Energy profile.	MEDIUM
INT-003-0	R1.1.3.	Ramp start time and duration (Balancing Authorities shall use the ramp duration established for their Interconnection unless they agree to alternative ramp duration.) Default ramps durations are as follows: Default ramp duration for the Eastern Interconnection shall be 10 minutes equally across the Interchange Schedule start and end times. Default ramp duration for the Western Interconnection shall be 20 minutes equally across the Interchange Schedule start and end times. Ramp durations for Interchange Schedules implemented for compliance with NERC's Disturbance Control Standard (recovery from a disturbance condition) and Interchange Transaction curtailment in response to line loading relief procedures may be shorter than the above defaults, but must be identical for the Sending Balancing Authority and Receiving Balancing Authority	MEDIUM
INT-003-0	R1.2.	If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.	MEDIUM
INT-003-0	R1.3.	Balancing Authorities that implement Interchange Schedules that cross an Interconnection boundary shall use the same start time and Ramp durations.	MEDIUM
INT-003-0	R2.	Balancing Authorities shall implement Interchange Schedules only with Adjacent Balancing Authorities.	MEDIUM
INT-003-0	R3.	Balancing Authorities shall begin and end Interchange Schedules at a time agreed to by the Source Balancing Authority, Sink Balancing Authority, and Intermediate Balancing Authorities.	MEDIUM
INT-003-0	R4.	The Sink Balancing Authority shall be responsible for initiating implementation of each Interchange Transaction as tagged. Upon receiving composite approval from the Sink Balancing Authority, each Balancing Authority on the scheduling path shall enter confirmed Schedules into its Automatic Generation Control ACE equation.	MEDIUM
INT-003-0	R5.	Balancing Authorities shall operate such that Interchange Schedules do not knowingly cause any other systems to violate established operating criteria.	MEDIUM
INT-003-0	R6.	Balancing Authorities shall operate such that the maximum Net Interchange Schedule between any two Balancing Authorities does not exceed the lesser of:	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
INT-003-0	R6.1.	The total capacity of both the owned and arranged-for transmission facilities in service for any Transmission Service Provider along the path, or	MEDIUM
INT-003-0	R6.2.	The established network Total Transfer Capability between Balancing Authorities, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network.	MEDIUM
INT-004-0	R1.	If a Reliability Coordinator, Transmission Operator, or Source or Sink Balancing Authority, due to a reliability event, needs to modify an Interchange Transaction that is in progress or scheduled to be started, the entity shall, within 60 minutes of the start of the emergency Transaction, modify the Interchange Transaction Tag, and shall communicate the modification to the Sink Balancing Authority. Reliability events may include:	MEDIUM
INT-004-0	R1.1.	Transmission Loading Relief procedure curtailment — Eastern Interconnection.	MEDIUM
INT-004-0	R1.2.	Interconnection, regional, or local overload relief or congestion management procedures.	MEDIUM
INT-004-0	R1.3.	SOL or IROL potential or actual limit violation.	MEDIUM
INT-004-0	R1.4.	Loss of generation.	MEDIUM
INT-004-0	R1.5.	Loss of Load.	MEDIUM
INT-004-0	R2.	A Generator Operator or Load Serving Entity may request the Host Balancing Authority to modify an Interchange Transaction due to loss of generation or load.	LOWER
INT-004-0	R2.1.	When a loss of generation necessitates curtailing Interchange Transactions, the Source Balancing Authority shall coordinate the modifications to the appropriate tags.	LOWER
INT-004-0	R2.2.	When a loss of Load necessitates curtailing Interchange Transactions, the Sink Balancing Authority shall coordinate the modifications to the appropriate tags.	LOWER
INT-004-0	R3.	Upon receipt of modification to an Interchange Transaction as described in Requirement R1, the Sink Balancing Authority (Source Balancing Authority in the case of a loss of generation) shall communicate the modified information about the Interchange Transaction, including its composite approval status, to all Balancing Authorities and Transmission Service Providers on the Transaction path and the Purchasing-Selling Entity responsible for the Transaction.	LOWER
INT-004-0	R4.	At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction Tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.	LOWER
INT-004-0	R5.	The Purchasing-Selling Entity responsible for Tagging a Dynamic Interchange Schedule shall ensure the Tag is updated for the next available scheduling hour and future hours when any one of the following occur:	MEDIUM
INT-004-0	R5.1.	The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the Tag by more than +10%.	MEDIUM
INT-004-0	R5.2.	The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the Tag by more than +25 megawatt-hours.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
INT-004-0	R5.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.	MEDIUM

The following table lists the Violation Risk Factors (VRFs) for the Version 0 Emergency Preparedness and Operations and Critical Infrastructure Protection standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF Survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
EOP-001-0	R1.	Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	HIGH
EOP-001-0	R2.	The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.	MEDIUM
EOP-001-0	R3.	Each Transmission Operator and Balancing Authority shall:	MEDIUM
EOP-001-0	R3.1.	Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.	MEDIUM
EOP-001-0	R3.2.	Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.	MEDIUM
EOP-001-0	R3.3.	Develop, maintain, and implement a set of plans for load shedding.	MEDIUM
EOP-001-0	R3.4.	Develop, maintain, and implement a set of plans for system restoration.	MEDIUM
EOP-001-0	R4.	Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:	MEDIUM
EOP-001-0	R4.1.	Communications protocols to be used during emergencies.	MEDIUM
EOP-001-0	R4.2.	A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.	MEDIUM
EOP-001-0	R4.3.	The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.	MEDIUM
EOP-001-0	R4.4.	Staffing levels for the emergency.	MEDIUM
EOP-001-0	R5.	Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.	MEDIUM
EOP-001-0	R6.	The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.	MEDIUM
EOP-001-0	R7.	The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
EOP-001-0	R7.1.	The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.	MEDIUM
EOP-001-0	R7.2.	The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.	MEDIUM
EOP-001-0	R7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)	MEDIUM
EOP-001-0	R7.4.	The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.	MEDIUM
EOP-002-0	R1.	Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	HIGH
EOP-002-0	R2.	Each Balancing Authority and Reliability Coordinator shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.	MEDIUM
EOP-002-0	R3.	A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	MEDIUM
EOP-002-0	R4.	A Reliability Coordinator that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to neighboring areas.	MEDIUM
EOP-002-0	R5.	A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	MEDIUM
EOP-002-0	R6.	A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	MEDIUM
EOP-002-0	R7.	If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:	HIGH
EOP-002-0	R7.1.	Loading all available generating capacity.	HIGH
EOP-002-0	R7.2.	Deploying all available operating reserve.	HIGH
EOP-002-0	R7.3.	Interrupting interruptible load and exports.	HIGH
EOP-002-0	R7.4.	Requesting emergency assistance from other Balancing Authorities.	HIGH
EOP-002-0	R7.5.	Declaring an Energy Emergency through its Reliability Coordinator; and	HIGH
EOP-002-0	R7.6.	Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		loads.	
EOP-002-0	R8.	Once the Balancing Authority has exhausted the steps listed in Requirement 7, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:	HIGH
EOP-002-0	R8.1.	Manually shed firm load without delay to return its ACE to zero; and	HIGH
EOP-002-0	R8.2.	Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.”	HIGH
EOP-002-0	R9.	A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	HIGH
EOP-002-0	R10.	When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 “Transmission Loading Relief Procedure” for explanation of Transmission Service Priorities):	HIGH
EOP-002-0	R10.1.	The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.	HIGH
EOP-002-0	R10.2.	The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.	HIGH
EOP-002-0	R10.3.	The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.	LOWER
EOP-002-0	R10.4.	The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.	LOWER
EOP-003-0	R1.	After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	HIGH
EOP-003-0	R2.	Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.	HIGH
EOP-003-0	R3.	Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.	HIGH
EOP-003-0	R4.	A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		power flow levels.	
EOP-003-0	R5.	A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	HIGH
EOP-003-0	R6.	After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	HIGH
EOP-003-0	R7.	The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.	HIGH
EOP-003-0	R8.	Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	HIGH
EOP-004-0	R1.	Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.	LOWER
EOP-004-0	R2.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.	MEDIUM
EOP-004-0	R3.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.	LOWER
EOP-004-0	R3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.	LOWER
EOP-004-0	R3.2.	Applicable reporting forms are provided in Attachments 022-1 and 022-2.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
EOP-004-0	R3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.	LOWER
EOP-004-0	R3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.	LOWER
EOP-004-0	R4.	When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.	LOWER
EOP-004-0	R5.	The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.	LOWER
EOP-005-0	R1.	Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005-0 in developing a restoration plan.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
EOP-005-0	R2.	Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.	HIGH
EOP-005-0	R3.	Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.	MEDIUM
EOP-005-0	R4.	Each Transmission Operator shall coordinate its restoration plans with Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.	MEDIUM
EOP-005-0	R5.	Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.	MEDIUM
EOP-005-0	R6.	Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.	HIGH
EOP-005-0	R7.	Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	HIGH
EOP-005-0	R8.	Each Transmission Operator shall ensure the availability and location of black start capability within its area to meet the needs of the restoration plan.	MEDIUM
EOP-005-0	R9.	Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.	HIGH
EOP-005-0	R9.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).	HIGH
EOP-005-0	R9.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators online, or load shedding.	HIGH
EOP-005-0	R9.3.	The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.	HIGH
EOP-005-0	R9.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.	HIGH
EOP-005-0	R9.5.	The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:	HIGH
EOP-005-0	R9.5.1.	Voltage, frequency, and phase angle permit.	HIGH
EOP-005-0	R9.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		considered.	
EOP-005-0	R9.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.	HIGH
EOP-005-0	R9.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.	HIGH
EOP-006-0	R1.	Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with NERC and regional requirements.	MEDIUM
EOP-006-0	R2.	The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.	HIGH
EOP-006-0	R3.	The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator restoration plans and that ensures reliability is maintained during system restoration events.	MEDIUM
EOP-006-0	R4.	The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Transmission Operators or Balancing Authorities not immediately involved in restoration.	MEDIUM
EOP-006-0	R5.	Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on adjacent Transmission Operator, Balancing Authority, or Reliability Coordinator Areas.	HIGH
EOP-006-0	R6.	The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.	MEDIUM
EOP-007-0	R1.	[High only because of R 1.2's importance.] Each Regional Reliability Organization shall establish and maintain a system BCP, as part of an overall coordinated Regional SRP. The Regional SRP shall include requirements for verification through analysis how system blackstart generating units shall perform their intended functions and shall be sufficient to meet SRP expectations. The Regional Reliability Organization shall coordinate with and among other Regional Reliability Organizations as appropriate in the development of its BCP. The BCP shall include:	MEDIUM
EOP-007-0	R1.1.	[High only because of R 1.2's importance.] A requirement to have a database that contains all blackstart generators designated for use in an SRP within the respective areas. This database shall be updated on an annual basis. The database shall include the name, location, megawatt capacity, type of unit, latest date of test, and starting method.	MEDIUM
EOP-007-0	R1.2.	[High only because of R 1.2's importance.] A requirement to demonstrate that blackstart units perform their intended functions as required in the Regional SRP. This requirement can be met through either simulation or testing. The BCP must consider the availability of designated BCP units and initial transmission switching requirements.	MEDIUM
EOP-007-0	R1.3.	[High only because of R 1.2's importance.] Blackstart unit testing requirements including, but not limited to:	MEDIUM
EOP-007-0	R1.3.1.	Testing frequency (minimum of one third of the units each	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		year).	
EOP-007-0	R1.3.2.	[High only because of R 1.2's importance.] Type of test required, including the requirement to start when isolated from the system.	MEDIUM
EOP-007-0	R1.3.3.	[High only because of R 1.2's importance.] Minimum duration of tests.	MEDIUM
EOP-007-0	R1.4.	[High only because of R 1.2's importance.] A requirement to review and update the Regional BCP at least every five years.	MEDIUM
EOP-007-0	R2.	The Regional Reliability Organization shall provide documentation of its system BCPs to NERC within 30 calendar days of a request.	LOWER
EOP-008-0	R1.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:	MEDIUM
EOP-008-0	R1.1.	The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.	MEDIUM
EOP-008-0	R1.2.	The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.	MEDIUM
EOP-008-0	R1.3.	The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.	MEDIUM
EOP-008-0	R1.4.	The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.	MEDIUM
EOP-008-0	R1.5.	The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.	MEDIUM
EOP-008-0	R1.6.	The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.	MEDIUM
EOP-008-0	R1.7.	The plan shall be reviewed and updated annually.	MEDIUM
EOP-008-0	R1.8.	Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.	MEDIUM
EOP-009-0	R1.	The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.	MEDIUM
EOP-009-0	R2.	The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
CIP-001-0	R1.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection.	MEDIUM
CIP-001-0	R2.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.	MEDIUM
CIP-001-0	R3.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.	MEDIUM
CIP-001-0	R4.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.	MEDIUM

The following table lists the Violation Risk Factors (VRF s) for the Version 0 Communications and Facilities Design, Connections and Maintenance standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
COM-001-0	R1.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities the exchange of Interconnection and operating information:	MEDIUM
COM-001-0	R1.1.	Internally.	MEDIUM
COM-001-0	R1.2.	Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.	MEDIUM
COM-001-0	R1.3.	With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.	MEDIUM
COM-001-0	R1.4.	Where applicable, these facilities shall be redundant and diversely routed.	MEDIUM
COM-001-0	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.	MEDIUM
COM-001-0	R3.	Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.	LOWER
COM-001-0	R4.	Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.	MEDIUM
COM-001-0	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.	LOWER
COM-001-0	R6.	Each NERCnet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, “NERCnet Security Policy.”	LOWER
COM-002-0	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
COM-002-0	R2.	Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated. The following information shall be conveyed to others in the Interconnection via an Interconnection-wide telecommunications system:	HIGH
COM-002-0	R2.1.	The Balancing Authority is unable to purchase capacity or energy to meet its demand and reserve requirements on a day-ahead or hour-by-hour basis.	MEDIUM
COM-002-0	R2.2.	The Transmission Operator recognizes that potential or actual line loadings, and voltage or reactive levels are such that a single Contingency could threaten the reliability of the Interconnection. (Once a single Contingency occurs, the Transmission Operator must prepare for the next Contingency.)	HIGH
COM-002-0	R2.3.	The Transmission Operator anticipates initiating a 3% or greater voltage reduction, public appeals for load curtailments, or firm load shedding for other than local problems.	HIGH
FAC-001-0	R1.1.	Generation facilities,	MEDIUM
FAC-001-0	R1.2.	Transmission facilities, and	MEDIUM
FAC-001-0	R1.3.	End-user facilities	MEDIUM
FAC-001-0	R2.	The Transmission Owner’s facility connection requirements shall address, but are not limited to, the following items:	MEDIUM
FAC-001-0	R2.1.1.	Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.	MEDIUM
FAC-001-0	R2.1.12.	Synchronizing of facilities.	MEDIUM
FAC-001-0	R2.1.15.	Inspection requirements for existing or new facilities.	MEDIUM
FAC-001-0	R2.1.2.	Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.	MEDIUM
FAC-001-0	R1.	The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner’s facility connection requirements shall address connection requirements for:	MEDIUM
FAC-001-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM
FAC-001-0	R2.1.10.	Power quality impacts.	MEDIUM
FAC-001-0	R2.1.11.	Equipment Ratings.	MEDIUM
FAC-001-0	R2.1.13.	Maintenance coordination.	MEDIUM
FAC-001-0	R2.1.14.	Operational issues (abnormal frequency and voltages).	MEDIUM
FAC-001-0	R2.1.16.	Communications and procedures during normal and emergency operating conditions.	MEDIUM
FAC-001-0	R2.1.3.	Voltage level and MW and MVAR capacity or demand at point of connection.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
FAC-001-0	R2.1.4.	Breaker duty and surge protection.	MEDIUM
FAC-001-0	R2.1.5.	System protection and coordination.	MEDIUM
FAC-001-0	R2.1.6.	Metering and telecommunications.	MEDIUM
FAC-001-0	R2.1.7.	Grounding and safety issues.	MEDIUM
FAC-001-0	R2.1.8.	Insulation and insulation coordination.	MEDIUM
FAC-001-0	R2.1.9.	Voltage, Reactive Power, and power factor control.	MEDIUM
FAC-001-0	R3.	The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).	MEDIUM
FAC-002-0	R1.	The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:	MEDIUM
FAC-002-0	R1.1.	Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.	MEDIUM
FAC-002-0	R1.2.	Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.	MEDIUM
FAC-002-0	R1.3.	Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.	MEDIUM
FAC-002-0	R1.4.	Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.	MEDIUM
FAC-002-0	R1.5.	Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.	MEDIUM
FAC-002-0	R2.	The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) Regional Reliability Organization(s) and NERC on request (within 30 calendar days).	LOWER
FAC-003-0	R1.2.	Trimming clearances.	HIGH
FAC-003-0	R2.	Each Transmission Owner shall report to its Regional Reliability Organization all vegetation-related outages on transmission circuits 200 kV and higher and any other lower voltage lines designated by the Regional Reliability Organization to be critical to the reliability of the electric system.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
FAC-003-0	R1.	Each Transmission Owner shall have a vegetation management program to prevent transmission line contact with vegetation. The vegetation management program shall include the following three elements:	HIGH
FAC-003-0	R1.1.	Inspection requirements.	HIGH
FAC-003-0	R1.3.	Annual work plan.	HIGH
FAC-004-0	R1.1.2.	Transformers.	LOWER
FAC-004-0	R1.	The Transmission Owner and Generator Owner shall each document the methodology(ies) used to determine its electrical equipment and Facility Rating. Further, the methodology(ies) shall comply with applicable Regional Reliability Organization requirements. The documentation shall address and include	LOWER
FAC-004-0	R1.1.	The methodology(ies) used to determine equipment and Facility Rating of the items listed for both normal and emergency conditions:	LOWER
FAC-004-0	R1.1.1.	Transmission circuits.	LOWER
FAC-004-0	R1.1.3.	Series and shunt reactive elements.	LOWER
FAC-004-0	R1.1.4.	Terminal equipment (e.g., switches, breakers, current transformers, etc).	LOWER
FAC-004-0	R1.1.5.	VAR compensators.	LOWER
FAC-004-0	R1.1.6.	High voltage direct current converters.	LOWER
FAC-004-0	R1.1.7.	Any other device listed as a Limiting Element.	LOWER
FAC-004-0	R1.2.	The Rating of a facility shall not exceed the Rating(s) of the most Limiting Element(s) in the circuit, including terminal connections and associated equipment.	MEDIUM
FAC-004-0	R1.3.	In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the Rating for that facility.	MEDIUM
FAC-004-0	R1.4.	Ratings of jointly-owned and jointly-operated facilities shall be coordinated among the joint owners and joint operators resulting in a single set of Ratings.	LOWER
FAC-004-0	R1.5.	The documentation shall identify the assumptions used to determine each of the equipment and Facility Ratings, including references to industry Rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal Ratings and variations in assumptions shall be included.	LOWER
FAC-004-0	R2.	The Transmission Owner and Generator Owner shall provide documentation of the methodology(ies) used to determine its transmission equipment and Facility Ratings to the Regional Reliability Organization(s) and NERC on request (30 calendar days).	LOWER
FAC-005-0	R1.	The transmission Owner, and Generator Owner shall each have on file or be able to readily provide, a document or database identifying the Normal and Emergency Ratings of all of its transmission facilities (e.g., lines, transformers, terminal equipment, and storage devices) that are part of the interconnected transmission systems. Seasonal variations in Ratings shall be included as appropriate.	LOWER
FAC-005-0	R1.1.	The Ratings shall be consistent with the entity's methodology(ies) for determining Facility Ratings and shall be updated as facility changes occur.	MEDIUM
FAC-005-0	R2.	The transmission Owner and Generator Owner shall provide the Normal and Emergency Facility Ratings of all its transmission facilities to the Regional Reliability	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		Organization(s) and NERC on request (30 calendar days).	

The following table lists the Violation Risk Factors (VRFs) for the Version 0 Interconnection Reliability Operations and Coordination standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
IRO-001-0	R1.	Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.	HIGH
IRO-001-0	R2.	The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.	HIGH
IRO-001-0	R3.	The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.	HIGH
IRO-001-0	R4.	Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.	MEDIUM
IRO-001-0	R5.	The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.	LOWER
IRO-001-0	R6.	The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.	MEDIUM
IRO-001-0	R7.	The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.	HIGH
IRO-001-0	R8.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.	HIGH
IRO-001-0	R9.	The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
IRO-002-0	R1.	Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.	HIGH
IRO-002-0	R2.	Each Reliability Coordinator shall determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability Coordinators.	MEDIUM
IRO-002-0	R3.	Each Reliability Coordinator – or its Transmission Operators and Balancing Authorities – shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.	MEDIUM
IRO-002-0	R4.	Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.	MEDIUM
IRO-002-0	R5.	Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.	HIGH
IRO-002-0	R6.	Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.	HIGH
IRO-002-0	R7.	Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.	HIGH
IRO-002-0	R8.	Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.	HIGH
IRO-002-0	R9.	Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		outages.	
IRO-003-0	R1.	Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.	HIGH
IRO-003-0	R2.	When a Reliability Coordinator is aware of an operational concern, such as declining voltages, excessive reactive flows, or an IROL violation, in a neighboring Reliability Coordinator Area, it shall contact the Reliability Coordinator in whose area the operational concern was observed. The two Reliability Coordinators shall coordinate any actions, including emergency assistance, required to mitigate the operational concern.	HIGH
IRO-003-0	R3.	Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.	HIGH
IRO-004-0	R1.	Each Reliability Coordinator shall conduct next-day reliability analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.	HIGH
IRO-004-0	R2.	Each Reliability Coordinator shall pay particular attention to parallel flows to ensure one Reliability Coordinator Area does not place an unacceptable or undue Burden on an adjacent Reliability Coordinator Area.	HIGH
IRO-004-0	R3.	Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.	HIGH
IRO-004-0	R4.	Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
IRO-004-0	R5.	Each Reliability Coordinator shall share the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time for the Eastern Interconnection and 1500 Pacific Standard Time for the Western Interconnection, unless circumstances warrant otherwise.	HIGH
IRO-004-0	R6.	When conditions warrant, the Reliability Coordinator shall initiate a conference call or other appropriate communications to address the results of its reliability analyses.	HIGH
IRO-004-0	R7.	If the results of these studies indicate potential SOL or IROL violations, the Reliability Coordinator shall issue the appropriate alerts via the Reliability Coordinator Information System (RCIS) and direct its Transmission Operators, Balancing Authorities and Transmission Service Providers to take any necessary action the Reliability Coordinator deems appropriate to address the potential SOL or IROL violation.	HIGH
IRO-004-0	R8.	Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.	HIGH
IRO-005-0	R1.	Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:	HIGH
IRO-005-0	R1.1.	Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	HIGH
IRO-005-0	R1.2.	Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	HIGH
IRO-005-0	R1.3.	Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	HIGH
IRO-005-0	R1.4.	System real and reactive reserves (actual versus required).	HIGH
IRO-005-0	R1.5.	Capacity and energy adequacy conditions.	HIGH
IRO-005-0	R1.6.	Current ACE for all its Balancing Authorities.	HIGH
IRO-005-0	R1.7.	Current local or Transmission Loading Relief procedures in effect.	HIGH
IRO-005-0	R1.8.	Planned generation dispatches.	HIGH
IRO-005-0	R1.9.	Planned transmission or generation outages.	HIGH
IRO-005-0	R1.10.	Contingency events.	HIGH
IRO-005-0	R2.	Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
IRO-005-0	R3.	As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.	HIGH
IRO-005-0	R4.	Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	HIGH
IRO-005-0	R5.	Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.	HIGH
IRO-005-0	R6.	Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.	HIGH
IRO-005-0	R7.	The Reliability Coordinator shall participate in NERC hotline discussions, assist in the assessment of reliability of the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The Reliability Coordinator shall disseminate such information within its Reliability Coordinator Area, as required.	HIGH
IRO-005-0	R8.	Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.	HIGH
IRO-005-0	R9.	The Reliability Coordinator shall coordinate with other Reliability Coordinators and Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with other Reliability Coordinators and Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.	HIGH
IRO-005-0	R10.	As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		Coordinator Areas or Balancing Authorities.	
IRO-005-0	R11.	The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. If a Frequency Error, Time Error, or inadvertent problem occurs outside of the Reliability Coordinator Area, the Reliability Coordinator shall initiate a NERC hotline call to discuss the Frequency Error, Time Error, or Inadvertent Interchange with other Reliability Coordinators. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.	HIGH
IRO-005-0	R12.	Whenever a Special Protection System that may have an inter-Balancing Authority, inter-Transmission Operator, or inter-Reliability Coordinator Area impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.	HIGH
IRO-005-0	R13.	Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.	HIGH
IRO-005-0	R14.	Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.	MEDIUM
IRO-005-0	R15.	Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, and all impacted Reliability Coordinators within the Interconnection via the Reliability Coordinator Information System (RCIS) without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, and Reliability Coordinators when the transmission problem has been mitigated.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
IRO-005-0	R16.	Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.	HIGH
IRO-005-0	R17.	When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.	HIGH
IRO-006-0	R1.	A Reliability Coordinator shall take appropriate actions in accordance with established policies, procedures, authority, and expectations to relieve transmission loading.	HIGH
IRO-006-0	R2.	A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, at its discretion, select from either a “local” (Regional, Interregional, or subregional) transmission loading relief procedure or an Interconnection-wide procedure.	HIGH
IRO-006-0	R2.1.	The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection is provided in Attachment 1-IRO-006-0.	HIGH
IRO-006-0	R2.2.	The equivalent Interconnection-wide transmission loading relief procedure for use in the Western Interconnection is the “WSCC Unscheduled Flow Mitigation Plan,” provided at: http://www.wecc.biz/documents/publications/UFAS_mitigation_plan_re v_2001-clean_8-8-03.pdf.	HIGH
IRO-006-0	R2.3.	The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at: http://www.ercot.com/tac/retailisoadhoccommittee/protocols/keydocs/d raftercotprotocols.htm.	HIGH
IRO-006-0	R3.	The Reliability Coordinator may use local transmission loading relief or congestion management procedures, provided the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party to those procedures.	HIGH
IRO-006-0	R4.	A Reliability Coordinator may implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, the Reliability Coordinator shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure shall have such use approved by the NERC Operating Committee.	HIGH
IRO-006-0	R5.	When implemented, all Reliability Coordinators shall comply with the provisions of the Interconnection-wide procedure including, for example, action by Reliability Coordinators in other Interconnections to curtail an Interchange Transaction that crosses an Interconnection boundary.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
IRO-006-0	R6.	During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with interchange scheduling standards INT-001 through INT-004.	HIGH

The following table lists the Violation Risk Factors (VRFs) for the Version 0 Modeling, Data, and Analysis standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
MOD-001-0	R1.	Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. (Certain systems that are not required to post ATC values are exempt from this standard.) The Regional Reliability Organization's TTC and ATC methodology shall include each of the following nine items, and shall explain its use in determining TTC and ATC values:	LOWER
MOD-001-0	R1.1.	A narrative explaining how TTC and ATC values are determined.	LOWER
MOD-001-0	R1.2.	An accounting for how the reservations and schedules for firm (nonrecallable) and non-firm (recallable) transfers, both within and outside the Transmission Service Provider's system, are included.	LOWER
MOD-001-0	R1.3.	An accounting for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.	LOWER
MOD-001-0	R1.4.	A description of how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or because the reservations have not all been made.)	LOWER
MOD-001-0	R1.5.	A requirement that TTC and ATC values shall be determined and posted as follows:	LOWER
MOD-001-0	R1.6.	Indication of the treatment and level of customer demands, including interruptible demands.	LOWER
MOD-001-0	R1.7.	A specification of how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by Transmission Service Providers for the calculation of TTC and ATC values are shared and used within the Regional Reliability Organization and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regional Reliability Organizations. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.	LOWER
MOD-001-0	R1.8.	A description of how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.	LOWER
MOD-001-0	R1.9.	A description of the Regional Reliability Organization's practice on the netting of transmission reservations for purposes of TTC and ATC determination.	LOWER
MOD-001-0	R2.	The Regional Reliability Organization shall make the most recent version of the documentation of its TTC and ATC methodology available on a web site accessible by NERC, the Regional Reliability Organizations, and transmission users.	LOWER
MOD-001-0	R5.1.1.	Daily values for current week at least once per day.	LOWER
MOD-001-0	R5.1.2.	Daily values for day 8 through the first month at least once per week.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
MOD-001-0	R5.1.3.	Monthly values for months 2 through 13 at least once per month.	LOWER
MOD-002-0	R1.	Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to periodically review (at least annually) and ensure that the TTC and ATC calculations and resulting values of member Transmission Service Providers comply with the Regional TTC and ATC methodology and applicable Regional criteria.	LOWER
MOD-002-0	R2.	Each Regional Reliability Organization shall document the results of its periodic reviews of TTC and ATC.	LOWER
MOD-002-0	R3.	The Regional Reliability Organization shall provide the results of its most current reviews of TTC and ATC to NERC on request (within 30 calendar days).	LOWER
MOD-003-0	R1.	Each Regional Reliability Organization, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the Transmission Service Provider(s), and how these concerns or questions will be addressed. The Regional Reliability Organization's procedure shall specify the following:	LOWER
MOD-003-0	R1.1.	The name, telephone number and email address of a contact person to whom concerns are to be addressed.	LOWER
MOD-003-0	R1.2.	The amount of time it will take for a response.	LOWER
MOD-003-0	R1.3.	The manner in which the response will be communicated (e.g., email, letter, telephone, etc).	LOWER
MOD-003-0	R1.4.	What recourse a customer has if the response is deemed unsatisfactory.	LOWER
MOD-003-0	R2.	The Regional Reliability Organization shall post on a web site that is accessible by the Regional Reliability Organizations, NERC, and transmission users, its procedure for receiving and addressing concerns about the TTC and ATC methodology and TTC and ATC values of member Transmission Service Providers.	LOWER
MOD-004-0	R1.	Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional CBM methodology. The Regional Reliability Organization's CBM methodology shall include each of the following ten items, and shall explain its use in determining CBM value. Other items that are Regional Reliability Organization specific or that are considered in each respective Regional Reliability Organization methodology shall also be explained along with their use in determining CBM values.	LOWER
MOD-004-0	R1.1.	Specify that the method used by each Regional Reliability Organization member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.	LOWER
MOD-004-0	R1.10.	Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.	LOWER
MOD-004-0	R1.2.	Specify the frequency of calculation of the generation reliability requirement and associated CBM values.	LOWER
MOD-004-0	R1.3.	Require that generation unit outages considered in a Transmission Service Provider's CBM calculation be restricted to those units within the Transmission Service Provider's system.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
MOD-004-0	R1.4.	Require that CBM be preserved only on the Transmission Service Provider's System where the Load-Serving Entity's Load is located (i.e., CBM is an import quantity only).	LOWER
MOD-004-0	R1.5.	Describe the inclusion or exclusion rationale for generation resources of each Load- Serving Entity including those generation resources not directly connected to the Transmission Service Provider's system but serving Load-Serving Entity loads connected to the Transmission Service Provider's system.	LOWER
MOD-004-0	R1.6.	Describe the inclusion or exclusion rationale for generation connected to the Transmission Service Provider's system but not obligated to serve Native/Network Load connected to the Transmission Service Provider's system.	LOWER
MOD-004-0	R1.7.	Describe the formal process and rationale for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional Reliability Organization's CBM methodology.	LOWER
MOD-004-0	R1.8.	Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.	LOWER
MOD-004-0	R1.9.	Describe the inclusion or exclusion rationale for the loads of each Load-Serving Entity, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).	LOWER
MOD-004-0	R2.	The Regional Reliability Organization shall make the most recent version of the documentation of its CBM methodology available on a website accessible by NERC, the Regional Reliability Organizations, and transmission users.	LOWER
MOD-005-0	R1.	Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers to ensure that they comply with the Regional Reliability Organization's CBM methodology. The procedure shall include the following four requirements:	LOWER
MOD-005-0	R1.1.	Indicate the frequency under which the verification review shall be implemented.	LOWER
MOD-005-0	R1.2.	Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.	LOWER
MOD-005-0	R1.3.	Require review of the consistency of the Transmission Service Provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the components that comprise CBM are addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained.	LOWER
MOD-005-0	R1.4.	Require CBM values to be periodically updated (at least annually) and available to the Regional Reliability Organizations, NERC, and transmission users.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
MOD-005-0	R2.	Each Regional Reliability Organization shall document its CBM procedure and shall make its CBM review procedure available to NERC on request (within 30 calendar days).	LOWER
MOD-005-0	R3.	The Regional Reliability Organization shall provide documentation of the results of the most current implementation of its CBM review procedure to NERC on request (within 30 calendar days).	LOWER
MOD-006-0	R1.	Each Transmission Service Provider shall document its procedure on the use of Capacity Benefit Margin (CBM) (scheduling of energy against a CBM preservation). The procedure shall include the following three components:	LOWER
MOD-006-0	R1.1.	Require that CBM be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, Direct-Control Load Management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish Operating Reserves.	LOWER
MOD-006-0	R1.2.	Require that CBM shall only be used if the Load-Serving Entity calling for its use is experiencing a generation deficiency and its Transmission Service Provider is also experiencing Transmission Constraints relative to imports of energy on its transmission system.	LOWER
MOD-006-0	R1.3.	Describe the conditions under which CBM may be available as Non-Firm Transmission Service.	LOWER
MOD-006-0	R2.	Each Transmission Service Provider shall make its CBM use procedure available on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users..	LOWER
MOD-007-0	R1.	Each Transmission Service Provider that uses CBM shall report (to the Regional Reliability Organization, NERC and the transmission users) the use of CBM by the Load-Serving Entities' Loads on its system, except for CBM sales as Non-Firm Transmission Service. (This use of CBM shall be consistent with the Transmission Service Provider's procedure for use of CBM.)	LOWER
MOD-007-0	R2.	The Transmission Service Provider shall post the following three items within 15 calendar days after the use of CBM for an Energy Emergency. This posting shall be on a web site accessible by the Regional Reliability Organizations, NERC, and transmission users.	LOWER
MOD-007-0	R2.1.	Circumstances.	LOWER
MOD-007-0	R2.2.	Duration.	LOWER
MOD-007-0	R2.3.	Amount of CBM used.	LOWER
MOD-008-0	R1.	Each Regional Reliability Organization, in conjunction with its members, shall develop and document a Regional TRM methodology. The Region's TRM methodology shall specify or describe each of the following five items, and shall explain its use, if any, in determining TRM values. Other items that are Region-specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.	LOWER
MOD-008-0	R1.1.	Specify the update frequency of TRM calculations.	LOWER
MOD-008-0	R1.2.	Specify how TRM values are incorporated into Available Transfer Capability calculations.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
MOD-008-0	R1.3.	Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. Any component of uncertainty, other than those identified in MOD-008-0_R 1.3.1 through MOD-008-0_R 1.3.7, shall benefit the interconnected transmission systems as a whole before they shall be permitted to be included in TRM calculations. The components of uncertainty identified in MOD-008-0_R 1.3.1 through MOD-008-0_R 1.3.7, if applied, shall be accounted for solely in TRM and not CBM.	LOWER
MOD-008-0	R1.3.1.	Aggregate Load forecast error (not included in determining generation reliability requirements).	LOWER
MOD-008-0	R1.3.2.	Load distribution error.	LOWER
MOD-008-0	R1.3.3.	Variations in facility Loadings due to balancing of generation within a Balancing Authority Area.	LOWER
MOD-008-0	R1.3.4.	Forecast uncertainty in transmission system topology.	LOWER
MOD-008-0	R1.3.5.	Allowances for parallel path (loop flow) impacts.	LOWER
MOD-008-0	R1.3.6.	Allowances for simultaneous path interactions.	LOWER
MOD-008-0	R1.3.7.	Variations in generation dispatch.	LOWER
MOD-008-0	R1.3.8.	Short-term System Operator response (Operating Reserve actions not exceeding a 59-minute window).	LOWER
MOD-008-0	R1.4.	Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service.	LOWER
MOD-008-0	R1.5.	Describe the formal process for the Regional Reliability Organization to grant any variances to individual Transmission Service Providers from the Regional TRM methodology.	LOWER
MOD-008-0	R2.	The Regional Reliability Organization shall make its most recent version of the documentation of its TRM methodology available on a web site accessible by NERC, the Regional Reliability Organizations, and transmission users.	LOWER
MOD-009-0	R1.	Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review Transmission Reliability Margin (TRM) calculations and resulting values of member Transmission Service Providers to ensure they comply with the Regional TRM methodology, and are periodically updated and available to transmission users. This procedure shall include the following four required elements:	LOWER
MOD-009-0	R1.1.	Indicate the frequency under which the verification review shall be implemented.	LOWER
MOD-009-0	R1.2.	Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users.	LOWER
MOD-009-0	R1.3.	Require review of the consistency of the Transmission Service Provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained.	LOWER
MOD-009-0	R1.4.	Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regional Reliability Organizations, NERC, and transmission users.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
MOD-009-0	R2.	The Regional Reliability Organization shall make documentation of its Regional TRM review procedure available to NERC on request (within 30 calendar days).	LOWER
MOD-009-0	R3.	The Regional Reliability Organization shall make documentation of the results of the most current implementation of its TRM review procedure available to NERC on request (within 30 calendar days).	LOWER
MOD-010-0	R1.	The Transmission Owners, Transmission Planners Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1.	LOWER
MOD-010-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).	LOWER
MOD-011-0	R1.	The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:	HIGH
MOD-011-0	R1.1.	Bus (substation): name, nominal voltage, electrical demand supplied (consistent with the aggregated and dispersed substation demand data supplied per Reliability Standards MOD-016-0, MOD-017-0, and MOD-020-0), and location.	MEDIUM
MOD-011-0	R1.2.	Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum Ratings (net Real and Reactive Power), regulated bus and voltage set point, and equipment status.	MEDIUM
MOD-011-0	R1.3.	AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-004-0 and FAC-005-0) equipment status, and metering locations.	MEDIUM
MOD-011-0	R1.4.	DC Transmission Line (overhead and underground): line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.	MEDIUM
MOD-011-0	R1.5.	Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings (consistent with methodologies defined and Ratings supplied per Reliability Standard FAC-	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		004-0 and FAC-005-0.), and equipment status.	
MOD-011-0	R1.6.	Reactive Compensation (shunt and series capacitors and reactors): nominal Ratings, impedance, percent compensation, connection point, and controller device.	MEDIUM
MOD-011-0	R1.7.	Interchange Schedules: Existing and future Interchange Schedules and/or assumptions.	MEDIUM
MOD-011-0	R2.	The Regional Reliability Organizations within an Interconnection shall document their Interconnection's steady-state data requirements and reporting procedures, shall review those data requirements and reporting procedures (at least every five years), and shall make the data requirements and reporting procedures available on request (within five business days) to Regional Reliability Organizations, NERC, and all users of the interconnected transmission systems.	MEDIUM
MOD-012-0	R1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R 4.	MEDIUM
MOD-012-0	R2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. If no schedule exists, then these entities shall provide data on request (30 calendar days).	MEDIUM
MOD-013-0	R1.	The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements::	MEDIUM
MOD-013-0	R1.1.	Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.	HIGH
MOD-013-0	R1.1.1.	Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		generator units installed after 1990.	
MOD-013-0	R1.1.2.	The Interconnection-wide requirements shall specify unit size thresholds for permitting: The use of non-detailed vs. detailed models; The netting of small generating units with bus load, and; The combining of multiple generating units at one plant	MEDIUM
MOD-013-0	R1.2.	Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.	MEDIUM
MOD-013-0	R1.3.	Dynamics data representing electrical demand characteristics as a function of frequency and voltage.	LOWER
MOD-013-0	R1.4.	Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010-0_R 1.	LOWER
MOD-013-0	R2.	The Regional Reliability Organization shall participate in the documentation of its Interconnection's data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).	LOWER
MOD-014-0	R1.	The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of solved (converged) Interconnection-specific steady-state system models. The Interconnection-specific models shall include near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels.	LOWER
MOD-014-0	R2.	The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop steady-state system models annually for selected study years, as determined by the Regional Reliability Organizations within its Interconnection. The Regional Reliability Organization shall provide the most recent solved (converged) Interconnection-specific steady-state models to NERC in accordance with each Interconnection's schedule for submission.	LOWER
MOD-015-0	R1.	The Regional Reliability Organization(s) within each Interconnection shall coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-specific dynamics system models linked to the steady-state system models, as appropriate, of Reliability Standard MOD-014-0_R 1.	LOWER
MOD-015-0	R1.1.	The Regional Reliability Organization(s) shall develop Interconnection-specific dynamics system models for at least two timeframes (present or near-term model and a future or longer-term model), and additional seasonal and demand level models, as necessary, to analyze the dynamic response of that Interconnection.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
MOD-015-0	R2.	The Regional Reliability Organization(s) within each Interconnection shall develop Interconnection dynamics system models for their Interconnection annually for selected study years as determined by the Regional Reliability Organization(s) within each Interconnection and shall provide the most recent initialized (approximately 25 seconds, no-fault) models to NERC in accordance with each Interconnection's schedule for submission.	MEDIUM
MOD-016-0	R1.	The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.	MEDIUM
MOD-016-0	R1.1.	The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005-0, TPL-006-0, MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016, MOD-017-0, MOD-018-0, MOD-019-0, MOD-020-0, and MOD-021-0.	MEDIUM
MOD-016-0	R2.	The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).	MEDIUM
MOD-017-0	R1.	The Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-0_R 1.	LOWER
MOD-017-0	R1.1.	Integrated hourly demands in megawatts (MW) for the prior year.	LOWER
MOD-017-0	R1.2.	Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year.	LOWER
MOD-017-0	R1.3.	Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.	LOWER
MOD-017-0	R1.4.	Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.	LOWER
MOD-018-0	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner's report of actual and forecast demand data (reported on either an aggregated or dispersed basis) shall:	LOWER
MOD-018-0	R1.1.	Indicate whether the demand data of nonmember entities within an area or Regional Reliability Organization are included, and	LOWER
MOD-018-0	R1.2.	Address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and Net Energy for Load.	LOWER
MOD-018-0	R1.3.	Items (MOD-018-0_R 1.1) and (MOD-018-0_R 1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-0_R 1.	LOWER
MOD-018-0	R2.	The Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner shall each report data associated with Reliability Standard MOD-018-0_R1 to NERC, the Regional Reliability Organization, Load-Serving Entity, Planning Authority, and Resource Planner on request (within 30 calendar days).	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
MOD-019-0	R1.	The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R 1.	LOWER
MOD-020-0	R1.	The Load-Serving Entity, Transmission Planner, and Resource Planner shall each make known its amount of interruptible demands and Direct Control Load Management (DCLM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 calendar days.	LOWER
MOD-021-0	R1.	The Load-Serving Entity Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.	LOWER
MOD-021-0	R2.	The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R 1.	LOWER
MOD-021-0	R3.	The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).	LOWER

The following table lists the Violation Risk Factors (VRF s) for the Version 0 Personnel Performance, Training, and Qualifications standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
PER-001-0	R1.	Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.	HIGH
PER-002-0	R1.	Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.	HIGH
PER-002-0	R2.	Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:	HIGH
PER-002-0	R2.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.	HIGH
PER-002-0	R2.2.	Positions directly responsible for complying with NERC standards.	HIGH
PER-002-0	R3.	For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:	HIGH
PER-002-0	R3.1.	A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.	MEDIUM
PER-002-0	R3.2.	The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.	MEDIUM
PER-002-0	R3.3.	The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.	LOWER
PER-002-0	R3.4.	Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.	LOWER
PER-002-0	R4.	For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	HIGH
PER-003-0	R1.	Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:	HIGH
PER-003-0	R1.1.	Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.	HIGH
PER-003-0	R1.2.	Positions directly responsible for complying with NERC	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		standards.	
PER-004-0	R1.	Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.	HIGH
PER-004-0	R2.	All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.	HIGH
PER-004-0	R3.	Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.	HIGH
PER-004-0	R4.	Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.	HIGH
PER-004-0	R5.	Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.	MEDIUM

The following table lists the Violation Risk Factors (VRFs) for the Version 0 Protection and Control standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
PRC-001-0	R1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.	MEDIUM
PRC-001-0	R2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	MEDIUM
PRC-001-0	R2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.	HIGH
PRC-001-0	R2.2.	If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.	HIGH
PRC-001-0	R3.	A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.	HIGH
PRC-001-0	R3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.	HIGH
PRC-001-0	R3.2.	Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.	HIGH
PRC-001-0	R4.	Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.	HIGH
PRC-001-0	R5.	A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:	HIGH
PRC-001-0	R5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.	HIGH
PRC-001-0	R5.2.	Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.	HIGH
PRC-001-0	R6.	Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	MEDIUM
PRC-002-0	R1.	The Regional Reliability Organization shall develop comprehensive requirements for the installation of Disturbance monitoring equipment to ensure data is available to determine system performance and the causes of System Disturbances. The comprehensive requirements shall include	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		all of the following:	
PRC-002-0	R1.1.	Type of data recording capability (e.g., sequence-of-event, Fault recording, dynamic Disturbance recording).	LOWER
PRC-002-0	R1.2.	Equipment characteristics including but not limited to:	LOWER
PRC-002-0	R1.2.1.	Recording duration requirements.	LOWER
PRC-002-0	R1.2.2.	Time synchronization requirements.	LOWER
PRC-002-0	R1.2.3.	Data format requirements.	LOWER
PRC-002-0	R1.2.4.	Event triggering requirements	LOWER
PRC-002-0	R1.3.	Monitoring, recording, and reporting capabilities of the equipment.	LOWER
PRC-002-0	R1.3.1.	Voltage.	LOWER
PRC-002-0	R1.3.2.	Current.	LOWER
PRC-002-0	R1.3.3.	Frequency.	LOWER
PRC-002-0	R1.3.4.	MW and/or MVAR, as appropriate.	LOWER
PRC-002-0	R1.4.	Data retention capabilities (e.g., length of time data is to be available for retrieval).	LOWER
PRC-002-0	R1.5.	Regional coverage requirements (e.g., by voltage, geographic area, electric area or subarea).	LOWER
PRC-002-0	R1.6.	Installation requirements:	LOWER
PRC-002-0	R1.6.1.	Substations.	LOWER
PRC-002-0	R1.6.2.	Transmission lines.	LOWER
PRC-002-0	R1.6.3.	Generators.	LOWER
PRC-002-0	R1.7.	Responsibility for maintenance and testing.	LOWER
PRC-002-0	R1.8.	Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements.	MEDIUM
PRC-002-0	R2.	The Regional Reliability Organization shall provide its requirements for the installation of Disturbance monitoring equipment to other Regional Reliability Organizations and NERC on request (30 calendar days).	LOWER
PRC-003-0	R1.	Each Regional Reliability Organization shall have a procedure for the monitoring, review, analysis, and correction of all transmission protection system misoperations. Each Regional Reliability Organization's procedure shall include the following elements:	LOWER
PRC-003-0	R1.1.	Requirements for monitoring and analysis of all transmission protective device misoperations.	LOWER
PRC-003-0	R1.2.	Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affects the reliability of the Bulk Electric Systems as specified by the Regional Reliability Organization.	LOWER
PRC-003-0	R1.3.	Process for review, follow up, and documentation of corrective action plans for misoperations.	LOWER
PRC-003-0	R1.4.	Identification of the Regional Reliability Organization group responsible for the procedure and the process for Regional Reliability Organization approval of the procedure.	LOWER
PRC-003-0	R1.5.	Regional Reliability Organization definition of misoperations.	LOWER
PRC-003-0	R2.	Each Regional Reliability Organization shall maintain documentation of its procedure and provide it to NERC on request (within 30 calendar days).	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
PRC-004-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.	HIGH
PRC-004-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system shall provide to its affected Regional Reliability Organization and NERC on request (within 30 calendar days) documentation of the misoperations analyses and corrective actions according to the Regional Reliability Organization's procedures of Reliability Standard PRC-003-0_R 1.	LOWER
PRC-005-0	R1.	The Transmission Owner, Generator Owner and Distribution Provider that owns a transmission protection system shall have a transmission protection system maintenance and testing program in place. The program(s) shall include:	MEDIUM
PRC-005-0	R1.1.	Transmission protection system identification shall include but are not limited to:	HIGH
PRC-005-0	R1.1.1.	Relays.	HIGH
PRC-005-0	R1.1.2.	Instrument transformers.	HIGH
PRC-005-0	R1.1.3.	Communications systems, where appropriate.	HIGH
PRC-005-0	R1.1.4.	Batteries.	HIGH
PRC-005-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	HIGH
PRC-005-0	R1.3.	Summary of testing procedure.	HIGH
PRC-005-0	R1.4.	Schedule for system testing.	HIGH
PRC-005-0	R1.5.	Schedule for system maintenance.	HIGH
PRC-005-0	R1.6.	Date last tested/maintained.	HIGH
PRC-005-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system shall provide documentation of its transmission protection system program and its implementation to the appropriate Regional Reliability Organization and NERC on request (within 30 calendar days).	LOWER
PRC-006-0	R1.	Each Regional Reliability Organization shall develop, coordinate, and document an UFLS program, which shall include the following:	HIGH
PRC-006-0	R1.1.	Requirements for coordination of UFLS programs within the subregions, Regional Reliability Organization and, where appropriate, among Regional Reliability Organizations.	HIGH
PRC-006-0	R1.2.	Design details shall include, but are not limited to:	MEDIUM
PRC-006-0	R1.2.1.	Frequency set points.	HIGH
PRC-006-0	R1.2.2.	Size of corresponding load shedding blocks (% of connected loads.)	HIGH
PRC-006-0	R1.2.3.	Intentional and total tripping time delays.	HIGH
PRC-006-0	R1.2.4.	Generation protection.	HIGH
PRC-006-0	R1.2.5.	Tie tripping schemes.	HIGH
PRC-006-0	R1.2.6.	Islanding schemes.	HIGH
PRC-006-0	R1.2.7.	Automatic load restoration schemes.	MEDIUM
PRC-006-0	R1.2.8.	Any other schemes that are part of or impact the UFLS programs.	MEDIUM
PRC-006-0	R1.3.	A Regional Reliability Organization UFLS program database. This database shall be updated as specified in the Regional Reliability Organization program (but at least every five years) and shall include sufficient information to model the UFLS	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		program in dynamic simulations of the interconnected transmission systems.	
PRC-006-0	R1.4.	Assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:	HIGH
PRC-006-0	R1.4.1.	A review of the frequency set points and timing, and	HIGH
PRC-006-0	R1.4.2.	Dynamic simulation of possible Disturbance that cause the Region or portions of the Region to experience the largest imbalance between Demand (Load) and generation.	HIGH
PRC-006-0	R2.	The Regional Reliability Organization shall provide documentation of its UFLS program and its database information to NERC on request (within 30 calendar days).	LOWER
PRC-006-0	R3.	The Regional Reliability Organization shall provide documentation of the assessment of its UFLS program to NERC on request (within 30 calendar days).	LOWER
PRC-007-0	R1.	The Transmission Owner and Distribution Provider, with a UFLS program (as required by its Regional Reliability Organization) shall ensure that its UFLS program is consistent with its Regional Reliability Organization's UFLS program requirements.	MEDIUM
PRC-007-0	R2.	The Transmission Owner, Transmission Operator, Distribution Provider, and Load-Serving Entity that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide, and annually update, its underfrequency data as necessary for its Regional Reliability Organization to maintain and update a UFLS program database.	LOWER
PRC-007-0	R3.	The Transmission Owner and Distribution Provider that owns a UFLS program (as required by its Regional Reliability Organization) shall provide its documentation of that UFLS program to its Regional Reliability Organization on request (30 calendar days).	LOWER
PRC-008-0	R1.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment maintenance and testing program in place. This UFLS equipment maintenance and testing program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.	MEDIUM
PRC-008-0	R2.	The Transmission Owner and Distribution Provider with a UFLS program (as required by its Regional Reliability Organization) shall implement its UFLS equipment maintenance and testing program and shall provide UFLS maintenance and testing program results to its Regional Reliability Organization and NERC on request (within 30 calendar days).	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
PRC-009-0	R1.	The Transmission Owner, Transmission Operator, Load-Serving Entity and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program. The analysis shall address the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:	MEDIUM
PRC-009-0	R1.1.	A description of the event including initiating conditions.	MEDIUM
PRC-009-0	R1.2.	A review of the UFLS set points and tripping times.	MEDIUM
PRC-009-0	R1.3.	A simulation of the event.	MEDIUM
PRC-009-0	R1.4.	A summary of the findings.	MEDIUM
PRC-009-0	R2.	The Transmission Owner, Transmission Operator, Load-Serving Entity, and Distribution Provider that owns or operates a UFLS program (as required by its Regional Reliability Organization) shall provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event.	LOWER
PRC-010-0	R1.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).	MEDIUM
PRC-010-0	R1.1.	This assessment shall include, but is not limited to:	MEDIUM
PRC-010-0	R1.1.1.	Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.	MEDIUM
PRC-010-0	R1.1.2.	Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.	MEDIUM
PRC-010-0	R1.1.3.	A review of the voltage set points and timing.	MEDIUM
PRC-010-0	R2.	The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days).	LOWER
PRC-011-0	R1.1.1.	Relays.	MEDIUM
PRC-011-0	R1.1.2.	Instrument transformers.	MEDIUM
PRC-011-0	R1.1.4.	Batteries.	MEDIUM
PRC-011-0	R1.6.	Date last tested/maintained.	MEDIUM
PRC-011-0	R1.	The Transmission Owner and Distribution Provider that owns a UVLS system shall have a UVLS equipment maintenance and testing program in place. This program shall include:	MEDIUM
PRC-011-0	R1.1.	The UVLS system identification which shall include but is not limited to:	MEDIUM
PRC-011-0	R1.1.3.	Communications systems, where appropriate.	MEDIUM
PRC-011-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	MEDIUM
PRC-011-0	R1.3.	Summary of testing procedure.	MEDIUM
PRC-011-0	R1.4.	Schedule for system testing.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
PRC-011-0	R1.5.	Schedule for system maintenance.	MEDIUM
PRC-011-0	R2.	The Transmission Owner and Distribution Provider that owns a UVLS system shall provide documentation of its UVLS equipment maintenance and testing program and the implementation of that UVLS equipment maintenance and testing program to its Regional Reliability Organization and NERC on request (within 30 calendar days).	LOWER
PRC-012-0	R1.	Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:	MEDIUM
PRC-012-0	R1.3.	Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.	MEDIUM
PRC-012-0	R1.5.	Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.	MEDIUM
PRC-012-0	R1.1.	Description of the process for submitting a proposed SPS for Regional Reliability Organization review.	MEDIUM
PRC-012-0	R1.2.	Requirements to provide data that describes design, operation, and modeling of an SPS.	MEDIUM
PRC-012-0	R1.4.	Requirements to demonstrate that the inadvertent operation of an SPS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.	MEDIUM
PRC-012-0	R1.6.	Regional Reliability Organization definition of misoperation.	MEDIUM
PRC-012-0	R1.7.	Requirements for analysis and documentation of corrective action plans for all SPS misoperations.	MEDIUM
PRC-012-0	R1.8.	Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.	MEDIUM
PRC-012-0	R1.9.	Determination, as appropriate, of maintenance and testing requirements.	MEDIUM
PRC-012-0	R2.	The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its SPS review procedure on request (within 30 calendar days).	LOWER
PRC-013-0	R1.	The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:	LOWER
PRC-013-0	R1.1.	Design Objectives — Contingencies and system conditions for which the SPS was designed,	LOWER
PRC-013-0	R1.2.	Operation — The actions taken by the SPS in response to Disturbance conditions, and	LOWER
PRC-013-0	R1.3.	Modeling — Information on detection logic or relay settings that control operation of the SPS.	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
PRC-013-0	R2.	The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).	LOWER
PRC-014-0	R3.	The documentation of the Regional Reliability Organization's SPS assessment shall include the following elements:	LOWER
PRC-014-0	R3.3.	Identification of SPSs that were found not to comply with NERC standards and Regional Reliability Organization criteria.	LOWER
PRC-014-0	R3.4.	Discussion of any coordination problems found between a SPS and other protection and control systems.	LOWER
PRC-014-0	R3.5.	Provide corrective action plans for non-compliant SPSs.	
PRC-014-0	R1.	The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all SPSs installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.	MEDIUM
PRC-014-0	R2.	The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all SPSs installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).	LOWER
PRC-014-0	R3.1.	Identification of group conducting the assessment and the date the assessment was performed.	LOWER
PRC-014-0	R3.2.	Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.	LOWER
PRC-015-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R 1.	MEDIUM
PRC-015-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.	MEDIUM
PRC-015-0	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).	LOWER
PRC-016-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R 1.	MEDIUM
PRC-016-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.	MEDIUM
PRC-016-0	R3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).	LOWER

Standard Number	Requirement Number	Requirement	Violation Risk Factor
PRC-017-0	R1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:	HIGH
PRC-017-0	R1.1.	SPS identification shall include but is not limited to:	HIGH
PRC-017-0	R1.1.1.	Relays.	HIGH
PRC-017-0	R1.1.2.	Instrument transformers.	HIGH
PRC-017-0	R1.1.3.	Communications systems, where appropriate.	HIGH
PRC-017-0	R1.1.4.	Batteries.	HIGH
PRC-017-0	R1.2.	Documentation of maintenance and testing intervals and their basis.	HIGH
PRC-017-0	R1.3.	Summary of testing procedure.	HIGH
PRC-017-0	R1.4.	Schedule for system testing.	HIGH
PRC-017-0	R1.5.	Schedule for system maintenance.	HIGH
PRC-017-0	R1.6.	Date last tested/maintained.	MEDIUM
PRC-017-0	R2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).	LOWER

The following table lists the Violation Risk Factors (VRFs) for the Version 0 Transmission Operations and Voltage and Reactive standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TOP-001-0	R1.	Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	HIGH
TOP-001-0	R2.	Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	HIGH
TOP-001-0	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.	HIGH
TOP-001-0	R4.	Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	HIGH
TOP-001-0	R5.	Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	HIGH
TOP-001-0	R6.	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	HIGH
TOP-001-0	R7.	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:	HIGH
TOP-001-0	R7.1.	For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TOP-001-0	R7.2.	For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.	HIGH
TOP-001-0	R7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.	HIGH
TOP-001-0	R8.	During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	HIGH
TOP-002-0	R1.	Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	MEDIUM
TOP-002-0	R2.	Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	MEDIUM
TOP-002-0	R3.	Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	MEDIUM
TOP-002-0	R4.	Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	MEDIUM
TOP-002-0	R5.	Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	MEDIUM
TOP-002-0	R6.	Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TOP-002-0	R7.	Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	MEDIUM
TOP-002-0	R8.	Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	MEDIUM
TOP-002-0	R9.	Each Balancing Authority shall plan to meet Interchange Schedules and Ramps.	LOWER
TOP-002-0	R10.	Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	MEDIUM
TOP-002-0	R11.	The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	MEDIUM
TOP-002-0	R12.	The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	MEDIUM
TOP-002-0	R13.	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	MEDIUM
TOP-002-0	R14.	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:	MEDIUM
TOP-002-0	R14.1.	Changes in real and reactive output capabilities.	HIGH
TOP-002-0	R14.2.	Automatic Voltage Regulator status and mode setting.	LOWER
TOP-002-0	R15.	Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	LOWER
TOP-002-0	R16.	Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:	MEDIUM
TOP-002-0	R16.1.	Changes in transmission facility status.	HIGH
TOP-002-0	R16.2.	Changes in transmission facility rating.	HIGH
TOP-002-0	R17.	Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	HIGH
TOP-002-0	R18.	Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		referring to transmission facilities of an interconnected network.	
TOP-002-0	R19.	Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	MEDIUM
TOP-003-0	R1.	Generator Operators and Transmission Operators shall provide planned outage information.	MEDIUM
TOP-003-0	R1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.	MEDIUM
TOP-003-0	R1.2.	Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.	MEDIUM
TOP-003-0	R1.3.	Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	MEDIUM
TOP-003-0	R2.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	MEDIUM
TOP-003-0	R3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	MEDIUM
TOP-003-0	R4.	Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	MEDIUM
TOP-004-0	R1.	Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	HIGH
TOP-004-0	R2.	Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	HIGH
TOP-004-0	R3.	Each Transmission Operator shall, when practical, operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by Regional Reliability Organization policy.	HIGH
TOP-004-0	R4.	If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TOP-004-0	R5.	Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	HIGH
TOP-004-0	R6.	Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:	MEDIUM
TOP-004-0	R6.1.	Equipment ratings.	MEDIUM
TOP-004-0	R6.2.	Monitoring and controlling voltage levels and real and reactive power flows.	MEDIUM
TOP-004-0	R6.3.	Switching transmission elements.	MEDIUM
TOP-004-0	R6.4.	Planned outages of transmission elements.	MEDIUM
TOP-004-0	R6.5.	Development of IROLs and SOLs.	MEDIUM
TOP-004-0	R6.6.	Responding to IROL and SOL violations.	MEDIUM
TOP-005-0	R1.	Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.	MEDIUM
TOP-005-0	R1.1.	Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 “Electric System Reliability Data” and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.	MEDIUM
TOP-005-0	R2.	As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”	LOWER
TOP-005-0	R3.	Upon request, each Reliability Coordinator shall, via the ISN or equivalent system, exchange with other Reliability Coordinators operating data that are necessary to allow the Reliability Coordinators to perform operational reliability assessments and coordinate reliable operations. Reliability Coordinators shall share with each other the types of data listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to.	MEDIUM
TOP-005-0	R4.	Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	MEDIUM
TOP-005-0	R5.	Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		assessments and coordinate reliable operations.	
TOP-006-0	R1.	Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.	MEDIUM
TOP-006-0	R1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.	MEDIUM
TOP-006-0	R1.2.	Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.	MEDIUM
TOP-006-0	R2.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	HIGH
TOP-006-0	R3.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	LOWER
TOP-006-0	R4.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system’s near-term load pattern.	LOWER
TOP-006-0	R5.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	MEDIUM
TOP-006-0	R6.	Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	HIGH
TOP-006-0	R7.	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	HIGH
TOP-007-0	R1.	A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	HIGH
TOP-007-0	R2.	Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	HIGH
TOP-007-0	R3.	A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R 2.	HIGH
TOP-007-0	R4.	The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	HIGH
TOP-008-0	R1.	The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TOP-008-0	R2.	Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	HIGH
TOP-008-0	R3.	The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	HIGH
TOP-008-0	R4.	The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	MEDIUM
VAR-001-0	R1.	Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within their individual areas and with the areas of neighboring Transmission Operators.	HIGH
VAR-001-0	R2.	Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.	HIGH
VAR-001-0	R3.	Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.	HIGH
VAR-001-0	R4.	The Transmission Operator shall know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers.	MEDIUM
VAR-001-0	R5.	The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.	HIGH
VAR-001-0	R6.	Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.	HIGH
VAR-001-0	R7.	Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.	HIGH
VAR-001-0	R7.1.	Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.	HIGH
VAR-001-0	R8.	Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.	HIGH

Standard Number	Requirement Number	Requirement	Violation Risk Factor
VAR-001-0	R9.	Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of voltage regulators and power system stabilizers.	HIGH
VAR-001-0	R9.1.	When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.	HIGH
VAR-001-0	R10.	The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.	HIGH

The following table lists the Violation Risk Factors (VRF s) for the Version 0 Transmission Planning standards requirements. These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the VRF survey.

Violation Risk Factors — Version 0 Standards Matrix

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TPL-001-0	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:	HIGH
TPL-001-0	R1.1.	Be made annually.	MEDIUM
TPL-001-0	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM
TPL-001-0	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).	MEDIUM
TPL-001-0	R1.3.1.	Cover critical system conditions and study years as deemed appropriate by the entity performing the study.	MEDIUM
TPL-001-0	R1.3.2.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM
TPL-001-0	R1.3.3.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM
TPL-001-0	R1.3.4.	Have established normal (pre-contingency) operating procedures in place.	MEDIUM
TPL-001-0	R1.3.5.	Have all projected firm transfers modeled.	MEDIUM
TPL-001-0	R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.	MEDIUM
TPL-001-0	R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).	MEDIUM
TPL-001-0	R1.3.8.	Include existing and planned facilities.	MEDIUM
TPL-001-0	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM
TPL-001-0	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category A.	MEDIUM
TPL-001-0	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM
TPL-001-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.	MEDIUM
TPL-001-0	R2.1.1.	Including a schedule for implementation.	MEDIUM
TPL-001-0	R2.1.2.	Including a discussion of expected required in-service dates of	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		facilities.	
TPL-001-0	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM
TPL-001-0	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	LOWER
TPL-001-0	R3.	The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	LOWER
TPL-002-0	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:	MEDIUM
TPL-002-0	R1.1.	Be made annually.	MEDIUM
TPL-002-0	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM
TPL-002-0	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	MEDIUM
TPL-002-0	R1.3.1.	Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	MEDIUM
TPL-002-0	R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM
TPL-002-0	R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM
TPL-002-0	R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	MEDIUM
TPL-002-0	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM
TPL-002-0	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM
TPL-002-0	R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM
TPL-002-0	R1.3.5.	Have all projected firm transfers modeled.	MEDIUM
TPL-002-0	R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system Demands.	MEDIUM
TPL-002-0	R1.3.7.	Demonstrate that system performance meets Category B contingencies.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TPL-002-0	R1.3.8.	Include existing and planned facilities.	MEDIUM
TPL-002-0	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM
TPL-002-0	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category B of Table I.	MEDIUM
TPL-002-0	R1.5.	Consider all contingencies applicable to Category B.	MEDIUM
TPL-002-0	R2.	When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM
TPL-002-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM
TPL-002-0	R2.1.1.	Including a schedule for implementation.	MEDIUM
TPL-002-0	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM
TPL-002-0	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM
TPL-002-0	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	MEDIUM
TPL-002-0	R3.	The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.	LOWER
TPL-003-0	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:	HIGH
TPL-003-0	R1.1.	Be made annually.	MEDIUM
TPL-003-0	R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	MEDIUM
TPL-003-0	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	MEDIUM
TPL-003-0	R1.3.1.	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TPL-003-0	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM
TPL-003-0	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM
TPL-003-0	R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	MEDIUM
TPL-003-0	R1.3.5.	Have all projected firm transfers modeled.	MEDIUM
TPL-003-0	R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system demands.	MEDIUM
TPL-003-0	R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.	MEDIUM
TPL-003-0	R1.3.8.	Include existing and planned facilities.	MEDIUM
TPL-003-0	R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.	MEDIUM
TPL-003-0	R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM
TPL-003-0	R1.3.11.	Include the effects of existing and planned control devices.	MEDIUM
TPL-003-0	R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.	MEDIUM
TPL-003-0	R1.4.	Address any planned upgrades needed to meet the performance requirements of Category C.	MEDIUM
TPL-003-0	R1.5.	Consider all contingencies applicable to Category C.	MEDIUM
TPL-003-0	R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:	MEDIUM
TPL-003-0	R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	MEDIUM
TPL-003-0	R2.1.1.	Including a schedule for implementation.	MEDIUM
TPL-003-0	R2.1.2.	Including a discussion of expected required in-service dates of facilities.	MEDIUM
TPL-003-0	R2.1.3.	Consider lead times necessary to implement plans.	MEDIUM
TPL-003-0	R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	LOWER
TPL-003-0	R3.	The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	LOWER
TPL-004-0	R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:	MEDIUM
TPL-004-0	R1.1.	Be made annually.	MEDIUM
TPL-004-0	R1.2.	Be conducted for near-term (years one through five).	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
TPL-004-0	R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	MEDIUM
TPL-004-0	R1.3.1.	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	MEDIUM
TPL-004-0	R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.	MEDIUM
TPL-004-0	R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.	MEDIUM
TPL-004-0	R1.3.4.	Have all projected firm transfers modeled.	MEDIUM
TPL-004-0	R1.3.5.	Include existing and planned facilities.	MEDIUM
TPL-004-0	R1.3.6.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	MEDIUM
TPL-004-0	R1.3.7.	Include the effects of existing and planned protection systems, including any backup or redundant systems.	MEDIUM
TPL-004-0	R1.3.8.	Include the effects of existing and planned control devices.	MEDIUM
TPL-004-0	R1.3.9.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	MEDIUM
TPL-004-0	R1.4.	Consider all contingencies applicable to Category D.	MEDIUM
TPL-004-0	R2.	The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	LOWER
TPL-005-0	R1.4.	Inter-Regional reliability assessments to demonstrate that the performance of these systems is in compliance with NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0 and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting Adequacy and Security.	MEDIUM
TPL-005-0	R3.5.	Reliability impacts of new or proposed environmental rules and regulations.	MEDIUM
TPL-005-0	R3.6.	Reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the Adequacy of the interconnected Bulk Electric Systems in North America.	MEDIUM
TPL-005-0	R1.	Each Regional Reliability Organization shall annually conduct reliability assessments of its respective existing and planned Regional Bulk Electric System (generation and transmission facilities) for:	MEDIUM
TPL-005-0	R1.1.	Current year:	MEDIUM
TPL-005-0	R1.1.1.	Winter.	MEDIUM
TPL-005-0	R1.1.2.	Summer.	MEDIUM
TPL-005-0	R1.1.3.	Other system conditions as deemed appropriate by the	MEDIUM

Standard Number	Requirement Number	Requirement	Violation Risk Factor
		Regional Reliability Organization.	
TPL-005-0	R1.2.	Near-term planning horizons (years one through five). Detailed assessments shall be conducted.	MEDIUM
TPL-005-0	R1.3.	Longer-term planning horizons (years six through ten). Assessment shall focus on the analysis of trends in resources and transmission Adequacy, other industry trends and developments, and reliability concerns.	MEDIUM
TPL-005-0	R2.	The Regional Reliability Organization shall provide its Regional and Inter-Regional seasonal, near-term, and longer-term reliability assessments to NERC on an annual basis.	LOWER
TPL-005-0	R3.	The Regional Reliability Organization shall perform special reliability assessments as requested by NERC or the NERC Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:	MEDIUM
TPL-005-0	R3.1.	Security assessments.	MEDIUM
TPL-005-0	R3.2.	Operational assessments.	MEDIUM
TPL-005-0	R3.3.	Evaluations of emergency response preparedness.	MEDIUM
TPL-005-0	R3.4.	Adequacy of fuel supply and hydro conditions.	MEDIUM
TPL-006-0	R1.	Each Regional Reliability Organization shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and Bulk Electric System data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Reliability Standards and the respective Regional planning criteria. The facility and Bulk Electric System data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:	MEDIUM
TPL-006-0	R1.1.	Electric Demand and Net Energy for Load (actual and projected demands and Net Energy for Load, forecast methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management.)	MEDIUM
TPL-006-0	R1.2.	Resource Adequacy and supporting information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements.)	MEDIUM
TPL-006-0	R1.3.	Demand-Side resources and their characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.)	MEDIUM
TPL-006-0	R1.4.	Supply-side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.)	MEDIUM
TPL-006-0	R1.5.	Transmission system and supporting information (thermal, voltage, and Stability Limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems.)	MEDIUM
TPL-006-0	R1.6.	System operations and supporting information (extreme weather impacts, Interchange Transactions, and Congestion impacts on the reliability of the interconnected Bulk Electric Systems.)	MEDIUM
TPL-006-0	R1.7.	Environmental and regulatory issues and impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation.)	MEDIUM

Exhibit B

Proposed Violation Risk Factors for Version 1 Reliability Standards

Violation Risk Factors — Version 1 Standards Matrix

The following table lists the Violation Risk Factors (VRFs) for the requirements in the following Version 1 Balancing and Interchange standards:

BAL-006-1 — Inadvertent Interchange
INT-001-2 — Interchange Information
INT-003-1 — Interchange Transaction Information
INT-004-1 — Interchange Transaction Modification
INT-005-1 — Interchange Authority Distributes Arranged Interchange
INT-006-1 — Response to Interchange Authority
INT-007-1 — Interchange Confirmation
INT-008-1 — Interchange Authority Distributes Status
INT-009-1 — Implementation of Interchange
INT-010-1 — Interchange Coordination Exemptions

These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the Version 1 VRF survey.

BAL-006-1 — Inadvertent Interchange			
BAL-006-1	R1.	Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.	LOWER
BAL-006-1	R2.	Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.	LOWER
BAL-006-1	R3.	Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.	LOWER
BAL-006-1	R4.	Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:	LOWER
BAL-006-1	R4.1.	Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:	LOWER
BAL-006-1	R4.1.1.	The hourly values of Net Interchange Schedule.	LOWER
BAL-006-1	R4.1.2.	The hourly integrated megawatt-hour values of Net Actual Interchange.	LOWER
BAL-006-1	R4.2.	Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.	LOWER
BAL-006-1	R4.3.	A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the	LOWER

BAL-006-1 — Inadvertent Interchange			
		Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).	
BAL-006-1	R5.	Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.	LOWER

INT-001-2 — Interchange Information			
INT-001-2	R1.	The Load-Serving, Purchasing-Selling Entity shall ensure that Arranged Interchange is submitted to the Interchange Authority for:	LOWER
INT-001-2	R1.1.	All Dynamic Schedules at the expected average MW profile for each hour.	LOWER
INT-001-2	R2.	The Sink Balancing Authority shall ensure that Arranged Interchange is submitted to the Interchange Authority:	LOWER
INT-001-2	R2.1.	If a Purchasing-Selling Entity is not involved in the Interchange, such as delivery from a jointly owned generator.	LOWER
INT-001-2	R2.2.	For each bilateral Inadvertent Interchange payback.	LOWER

INT-003-1 — Interchange Transaction Information			
INT-003-1	R1.	Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.	MEDIUM
INT-003-1	R1.1.	The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including:	LOWER
INT-003-1	R1.1.1.	Interchange Schedule start and end time.	LOWER
INT-003-1	R1.1.2.	Energy profile.	LOWER
INT-003-1	R1.2.	If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.	MEDIUM

INT-004-1 — Interchange Transaction Modification			
INT-004-1	R1.	At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.	LOWER
INT-004-1	R2.	The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the	LOWER

INT-004-1 — Interchange Transaction Modification			
		following occurs:	
INT-004-1	R2.1.	The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +10%.	LOWER
INT-004-1	R2.2.	The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than +25 megawatt-hours.	LOWER
INT-004-1	R2.3.	A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.	LOWER

INT-005-1 — Interchange Authority Distributes Arranged Interchange			
INT-005-1	R1.	Prior to the expiration of the time period defined in the Timing Table, Column A, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment to all reliability entities involved in the Interchange.	MEDIUM
INT-005-1	R1.1.	When a Balancing Authority or Reliability Coordinator initiates a Curtailment to Confirmed or Implemented Interchange for reliability, the Interchange Authority shall distribute the Arranged Interchange information for reliability assessment only to the Source Balancing Authority and the Sink Balancing Authority.	MEDIUM

INT-006-1 — Response to Interchange Authority			
INT-006-1	R1.	Prior to the expiration of the reliability assessment period defined in the Timing Table, Column B, the Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange.	LOWER
INT-006-1	R1.1.	Each involved Balancing Authority shall evaluate the Arranged Interchange with respect to:	LOWER
INT-006-1	R1.1.1.	Energy profile (ability to support the magnitude of the Interchange).	LOWER
INT-006-1	R1.1.2.	Ramp (ability of generation maneuverability to accommodate).	LOWER
INT-006-1	R1.1.3.	Scheduling path (proper connectivity of Adjacent Balancing Authorities).	LOWER
INT-006-1	R1.2.	Each involved Transmission Service Provider shall confirm that the transmission service arrangements associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated.	LOWER

INT-007-1 — Interchange Confirmation			
INT-007-1	R1.	The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange by verifying the following:	LOWER
INT-007-1	R1.1.	Source Balancing Authority megawatts equal sink Balancing Authority megawatts (adjusted for losses, if appropriate).	LOWER
INT-007-1	R1.2.	All reliability entities involved in the Arranged Interchange are currently in the NERC registry.	LOWER
INT-007-1	R1.3.	The following are defined:	LOWER
INT-007-1	R1.3.1.	Generation source and load sink.	LOWER
INT-007-1	R1.3.2.	Megawatt profile.	LOWER
INT-007-1	R1.3.3.	Ramp start and stop times.	LOWER
INT-007-1	R1.3.4.	Interchange duration.	LOWER
INT-007-1	R1.4.	Each Balancing Authority and Transmission Service Provider that received the Arranged Interchange information from the Interchange Authority for reliability assessment has provided approval.	LOWER

INT-008-1 — Interchange Authority Distributes Status			
INT-008-1	R1.	Prior to the expiration of the time period defined in the Timing Table, Column C, the Interchange Authority shall distribute to all Balancing Authorities (including Balancing Authorities on both sides of a direct current tie), Transmission Service Providers and Purchasing-Selling Entities involved in the Arranged Interchange whether or not the Arranged Interchange has transitioned to a Confirmed Interchange.	LOWER
INT-008-1	R1.1.	For Confirmed Interchange, the Interchange Authority shall also communicate:	LOWER
INT-008-1	R1.1.1.	Start and stop times, ramps, and megawatt profile to Balancing Authorities.	LOWER
INT-008-1	R1.1.2.	Necessary Interchange information to NERC-identified reliability analysis services.	LOWER

INT-009-1 — Implementation of Interchange			
INT-009-1	R1.	The Balancing Authority shall implement Confirmed Interchange as received from the Interchange Authority.	MEDIUM

INT-010-1 — Interchange Coordination Exemptions			
INT-010-1	R1.	The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement shall ensure that a request for an Arranged Interchange is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no request for Arranged Interchange	LOWER

INT-010-1 — Interchange Coordination Exemptions			
		is required.	
INT-010-1	R2.	For a modification to an existing Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit the modified Arranged Interchange reflecting that modification within 60 minutes of the initiation of the event.	LOWER
INT-010-1	R3.	For a new Interchange schedule that is directed by a Reliability Coordinator for current or imminent reliability-related reasons, the Reliability Coordinator shall direct a Balancing Authority to submit an Arranged Interchange reflecting that Interchange schedule within 60 minutes of the initiation of the event.	LOWER

Violation Risk Factors — Version 1 Standards Matrix

The following table lists the Violation Risk Factors (VRFs) for the requirements in the following Version 1 Critical Infrastructure Protection standards:

CIP-002-1 — Critical Cyber Asset Identification
CIP-003-1 — Security Management Controls
CIP-004-1 — Personnel & Training
CIP-005-1 — Electronic Security Perimeter(s)
CIP-006-1 — Physical Security of Critical Cyber Assets
CIP-007-1 — Systems Security Management
CIP-008-1 — Incident Reporting and Response Planning
CIP-009-1 — Recovery Plans for Critical Cyber Assets

These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the Version 1 VRF survey.

CIP-002-1 — Critical Cyber Asset Identification			
CIP-002-1	R1.	Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.	LOWER
CIP-002-1	R1.1.	The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.	LOWER
CIP-002-1	R1.2.	The risk-based assessment shall consider the following assets:	LOWER
CIP-002-1	R1.2.1.	Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.	LOWER
CIP-002-1	R1.2.2.	Transmission substations that support the reliable operation of the Bulk Electric System.	LOWER
CIP-002-1	R1.2.3.	Generation resources that support the reliable operation of the Bulk Electric System.	LOWER
CIP-002-1	R1.2.4.	Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.	LOWER
CIP-002-1	R1.2.5.	Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.	LOWER
CIP-002-1	R1.2.6.	Special Protection Systems that support the reliable operation of the Bulk Electric System.	LOWER
CIP-002-1	R1.2.7.	Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.	LOWER
CIP-002-1	R2.	Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.	LOWER
CIP-002-1	R3.	Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible	MEDIUM

CIP-002-1 — Critical Cyber Asset Identification			
		Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:	
CIP-002-1	R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	
CIP-002-1	R3.2.	The Cyber Asset uses a routable protocol within a control center; or,	LOWER
CIP-002-1	R3.3.	The Cyber Asset is dial-up accessible.	LOWER
CIP-002-1	R4.	Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)	LOWER

CIP-003-1 — Security Management Controls			
CIP-003-1	R1.	Cyber Security Policy — The Responsible Entity shall document and implement a cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets. The Responsible Entity shall, at minimum, ensure the following:	LOWER
CIP-003-1	R1.1.	The cyber security policy addresses the requirements in Standards CIP-002 through CIP-009, including provision for emergency situations.	LOWER
CIP-003-1	R1.2.	The cyber security policy is readily available to all personnel who have access to, or are responsible for, Critical Cyber Assets.	LOWER
CIP-003-1	R1.3.	Annual review and approval of the cyber security policy by the senior manager assigned pursuant to R2.	LOWER
CIP-003-1	R2.	Leadership — The Responsible Entity shall assign a senior manager with overall responsibility for leading and managing the entity's implementation of, and adherence to, Standards CIP-002 through CIP-009.	LOWER
CIP-003-1	R2.1.	The senior manager shall be identified by name, title, business phone, business address, and date of designation.	LOWER
CIP-003-1	R2.2.	Changes to the senior manager must be documented within thirty calendar days of the effective date.	LOWER
CIP-003-1	R2.3.	The senior manager or delegate(s), shall authorize and document any exception from the requirements of the cyber security policy.	LOWER
CIP-003-1	R3.	Exceptions — Instances where the Responsible Entity cannot	LOWER

CIP-003-1 — Security Management Controls			
		conform to its cyber security policy must be documented as exceptions and authorized by the senior manager or delegate(s).	
CIP-003-1	R3.1.	Exceptions to the Responsible Entity's cyber security policy must be documented within thirty days of being approved by the senior manager or delegate(s).	LOWER
CIP-003-1	R3.2.	Documented exceptions to the cyber security policy must include an explanation as to why the exception is necessary and any compensating measures, or a statement accepting risk.	LOWER
CIP-003-1	R3.3.	Authorized exceptions to the cyber security policy must be reviewed and approved annually by the senior manager or delegate(s) to ensure the exceptions are still required and valid. Such review and approval shall be documented.	LOWER
CIP-003-1	R4.	Information Protection — The Responsible Entity shall implement and document a program to identify, classify, and protect information associated with Critical Cyber Assets.	LOWER
CIP-003-1	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.	
CIP-003-1	R4.2.	The Responsible Entity shall classify information to be protected under this program based on the sensitivity of the Critical Cyber Asset information.	LOWER
CIP-003-1	R4.3.	The Responsible Entity shall, at least annually, assess adherence to its Critical Cyber Asset information protection program, document the assessment results, and implement an action plan to remediate deficiencies identified during the assessment.	LOWER
CIP-003-1	R5.	Access Control — The Responsible Entity shall document and implement a program for managing access to protected Critical Cyber Asset information.	LOWER
CIP-003-1	R5.1.	The Responsible Entity shall maintain a list of designated personnel who are responsible for authorizing logical or physical access to protected information.	LOWER
CIP-003-1	R5.1.1.	Personnel shall be identified by name, title, business phone and the information for which they are responsible for authorizing access.	LOWER
CIP-003-1	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	
CIP-003-1	R5.2.	The Responsible Entity shall review at least annually the access privileges to protected information to confirm that access privileges are correct and that they correspond with the Responsible Entity's needs and appropriate personnel roles and responsibilities.	LOWER
CIP-003-1	R5.3.	The Responsible Entity shall assess and document at least annually the processes for controlling access privileges to protected information.	LOWER
CIP-003-1	R6.	Change Control and Configuration Management — The Responsible Entity shall establish and document a process of	LOWER

CIP-003-1 — Security Management Controls			
		change control and configuration management for adding, modifying, replacing, or removing Critical Cyber Asset hardware or software, and implement supporting configuration management activities to identify, control and document all entity or vendor-related changes to hardware and software components of Critical Cyber Assets pursuant to the change control process.	

CIP-004-1 — Personnel & Training			
CIP-004-1	R1.	Awareness — The Responsible Entity shall establish, maintain, and document a security awareness program to ensure personnel having authorized cyber or authorized unescorted physical access receive on-going reinforcement in sound security practices. The program shall include security awareness reinforcement on at least a quarterly basis using mechanisms such as: - Direct communications (e.g., emails, memos, computer based training, etc.); - Indirect communications (e.g., posters, intranet, brochures, etc.); - Management support and reinforcement (e.g., presentations, meetings, etc.).	LOWER
CIP-004-1	R2.	Training — The Responsible Entity shall establish, maintain, and document an annual cyber security training program for personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and review the program annually and update as necessary.	LOWER
CIP-004-1	R2.1.	This program will ensure that all personnel having such access to Critical Cyber Assets, including contractors and service vendors, are trained within ninety calendar days of such authorization.	LOWER
CIP-004-1	R2.2.	Training shall cover the policies, access controls, and procedures as developed for the Critical Cyber Assets covered by CIP-004, and include, at a minimum, the following required items appropriate to personnel roles and responsibilities:	LOWER
CIP-004-1	R2.2.1.	The proper use of Critical Cyber Assets;	LOWER
CIP-004-1	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	
CIP-004-1	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	
CIP-004-1	R2.2.4.	Action plans and procedures to recover or re-establish Critical Cyber Assets and access thereto following a Cyber Security Incident.	LOWER
CIP-004-1	R2.3.	The Responsible Entity shall maintain documentation that training is conducted at least annually, including the date the training was completed and attendance records.	LOWER
CIP-004-1	R3.	Personnel Risk Assessment —The Responsible Entity shall have a documented personnel risk assessment program, in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements, for personnel having authorized cyber or authorized unescorted physical access. A personnel risk assessment shall be conducted pursuant to that program within thirty days of such personnel being granted such access. Such program shall at a minimum include:	LOWER
CIP-004-1	R3.1.	The Responsible Entity shall ensure that each assessment	LOWER

CIP-004-1 — Personnel & Training			
		conducted include, at least, identity verification (e.g., Social Security Number verification in the U.S.) and seven-year criminal check. The Responsible Entity may conduct more detailed reviews, as permitted by law and subject to existing collective bargaining unit agreements, depending upon the criticality of the position.	
CIP-004-1	R3.2.	The Responsible Entity shall update each personnel risk assessment at least every seven years after the initial personnel risk assessment or for cause.	LOWER
CIP-004-1	R3.3.	The Responsible Entity shall document the results of personnel risk assessments of its personnel having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, and that personnel risk assessments of contractor and service vendor personnel with such access are conducted pursuant to Standard CIP-004.	LOWER
CIP-004-1	R4.	Access — The Responsible Entity shall maintain list(s) of personnel with authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including their specific electronic and physical access rights to Critical Cyber Assets.	LOWER
CIP-004-1	R4.1.	The Responsible Entity shall review the list(s) of its personnel who have such access to Critical Cyber Assets quarterly, and update the list(s) within seven calendar days of any change of personnel with such access to Critical Cyber Assets, or any change in the access rights of such personnel. The Responsible Entity shall ensure access list(s) for contractors and service vendors are properly maintained.	LOWER
CIP-004-1	R4.2.	The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets.	LOWER

CIP-005-1 — Electronic Security Perimeter(s)			
CIP-005-1	R1.	Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).	MEDIUM
CIP-005-1	R1.1.	Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).	LOWER
CIP-005-1	R1.2.	For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.	LOWER
CIP-005-1	R1.3.	Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).	LOWER

CIP-005-1 — Electronic Security Perimeter(s)			
CIP-005-1	R1.4.	Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005.	LOWER
CIP-005-1	R1.5.	Cyber Assets used in the access control and monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	
CIP-005-1	R1.6.	The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.	LOWER
CIP-005-1	R2.	Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).	LOWER
CIP-005-1	R2.1.	These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.	MEDIUM
CIP-005-1	R2.2.	At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.	MEDIUM
CIP-005-1	R2.3.	The Responsible Entity shall maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).	MEDIUM
CIP-005-1	R2.4.	Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.	LOWER
CIP-005-1	R2.5.	The required documentation shall, at least, identify and describe:	LOWER
CIP-005-1	R2.5.1.	The processes for access request and authorization.	LOWER
CIP-005-1	R2.5.2.	The authentication methods.	LOWER
CIP-005-1	R2.5.3.	The review process for authorization rights, in accordance with Standard CIP-004 Requirement R4.	LOWER
CIP-005-1	R2.5.4.	The controls used to secure dial-up accessible connections.	LOWER
CIP-005-1	R2.6.	Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.	LOWER

CIP-005-1 — Electronic Security Perimeter(s)			
CIP-005-1	R3.	Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.	LOWER
CIP-005-1	R3.1.	For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.	LOWER
CIP-005-1	R3.2.	Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.	LOWER
CIP-005-1	R4.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:	LOWER
CIP-005-1	R4.1.	A document identifying the vulnerability assessment process;	LOWER
CIP-005-1	R4.2.	A review to verify that only ports and services required for operations at these access points are enabled;	LOWER
CIP-005-1	R4.3.	The discovery of all access points to the Electronic Security Perimeter;	LOWER
CIP-005-1	R4.5.	A review of controls for default accounts, passwords, and network management community strings; and,	LOWER
CIP-005-1	R4.5.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	LOWER
CIP-005-1	R5.	Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005.	LOWER
CIP-005-1	R5.1.	The Responsible Entity shall ensure that all documentation required by Standard CIP-005 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005 at least annually.	LOWER
CIP-005-1	R5.2.	The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.	LOWER
CIP-005-1	R5.3.	The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	LOWER

CIP-006-1 — Physical Security of Critical Cyber Assets			
CIP-006-1	R1.	Physical Security Plan — The Responsible Entity shall create and maintain a physical security plan, approved by a senior manager or delegate(s) that shall address, at a minimum, the following:	MEDIUM
CIP-006-1	R1.1.	Processes to ensure and document that all Cyber Assets within an Electronic Security Perimeter also reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to the Critical Cyber Assets.	MEDIUM
CIP-006-1	R1.2.	Processes to identify all access points through each Physical Security Perimeter and measures to control entry at those access points.	MEDIUM
CIP-006-1	R1.3.	Processes, tools, and procedures to monitor physical access to the perimeter(s).	MEDIUM
CIP-006-1	R1.4.	Procedures for the appropriate use of physical access controls as described in Requirement R3 including visitor pass management, response to loss, and prohibition of inappropriate use of physical access controls.	MEDIUM
CIP-006-1	R1.5.	Procedures for reviewing access authorization requests and revocation of access authorization, in accordance with CIP-004 Requirement R4.	LOWER
CIP-006-1	R1.6.	Procedures for escorted access within the physical security perimeter of personnel not authorized for unescorted access.	MEDIUM
CIP-006-1	R1.7.	Process for updating the physical security plan within ninety calendar days of any physical security system redesign or reconfiguration, including, but not limited to, addition or removal of access points through the physical security perimeter, physical access controls, monitoring controls, or logging controls.	LOWER
CIP-006-1	R1.8.	Cyber Assets used in the access control and monitoring of the Physical Security Perimeter(s) shall be afforded the protective measures specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirement R2 and R3, Standard CIP-007, Standard CIP-008 and Standard CIP-009.	LOWER
CIP-006-1	R1.9.	Process for ensuring that the physical security plan is reviewed at least annually.	LOWER
CIP-006-1	R2.	Physical Access Controls — The Responsible Entity shall document and implement the operational and procedural controls to manage physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. The Responsible Entity shall implement one or more of the following physical access methods:	MEDIUM
CIP-006-1	R2.1.	Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.	MEDIUM
CIP-006-1	R2.2.	Special Locks: These include, but are not limited to, locks with "restricted key" systems, magnetic locks that can be operated remotely, and "man-trap" systems.	MEDIUM

CIP-006-1 — Physical Security of Critical Cyber Assets			
CIP-006-1	R2.3.	Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.	MEDIUM
CIP-006-1	R2.4.	Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access to the Critical Cyber Assets.	MEDIUM
CIP-006-1	R3.	Monitoring Physical Access — The Responsible Entity shall document and implement the technical and procedural controls for monitoring physical access at all access points to the Physical Security Perimeter(s) twenty-four hours a day, seven days a week. Unauthorized access attempts shall be reviewed immediately and handled in accordance with the procedures specified in Requirement CIP-008. One or more of the following monitoring methods shall be used:	MEDIUM
CIP-006-1	R3.1.	Alarm Systems: Systems that alarm to indicate a door, gate or window has been opened without authorization. These alarms must provide for immediate notification to personnel responsible for response.	MEDIUM
CIP-006-1	R3.2.	Human Observation of Access Points: Monitoring of physical access points by authorized personnel as specified in Requirement R2.3.	LOWER
CIP-006-1	R4.	Logging Physical Access — Logging shall record sufficient information to uniquely identify individuals and the time of access twenty-four hours a day, seven days a week. The Responsible Entity shall implement and document the technical and procedural mechanisms for logging physical entry at all access points to the Physical Security Perimeter(s) using one or more of the following logging methods or their equivalent:	LOWER
CIP-006-1	R4.1.	Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and monitoring method.	LOWER
CIP-006-1	R4.2.	Video Recording: Electronic capture of video images of sufficient quality to determine identity.	LOWER
CIP-006-1	R4.3.	Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access as specified in Requirement R2.3.	LOWER
CIP-006-1	R5.	Access Log Retention — The responsible entity shall retain physical access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008.	LOWER
CIP-006-1	R6.	Maintenance and Testing — The Responsible Entity shall implement maintenance and testing program to ensure that all physical security systems under Requirements R2, R3, and R4 function properly. The program must include, at a minimum, the following:	MEDIUM
CIP-006-1	R6.1.	Testing and maintenance of all physical security mechanisms on a cycle no longer than three years.	LOWER
CIP-006-1	R6.2.	Retention of testing and maintenance records for the cycle determined by the Responsible Entity in Requirement R6.1.	LOWER

CIP-006-1 — Physical Security of Critical Cyber Assets			
CIP-006-1	R6.3.	Retention of outage records regarding access controls, logging, and monitoring for a minimum of one calendar year.	LOWER

CIP-007-1 — Systems Security Management			
CIP-007-1	R1.	Test Procedures — The Responsible Entity shall ensure that new Cyber Assets and significant changes to existing Cyber Assets within the Electronic Security Perimeter do not adversely affect existing cyber security controls. For purposes of Standard CIP-007, a significant change shall, at a minimum, include implementation of security patches, cumulative service packs, vendor releases, and version upgrades of operating systems, applications, database platforms, or other third-party software or firmware.	MEDIUM
CIP-007-1	R1.1.	The Responsible Entity shall create, implement, and maintain cyber security test procedures in a manner that minimizes adverse effects on the production system or its operation.	LOWER
CIP-007-1	R1.2.	The Responsible Entity shall document that testing is performed in a manner that reflects the production environment.	LOWER
CIP-007-1	R1.3.	The Responsible Entity shall document test results.	LOWER
CIP-007-1	R2.	Ports and Services — The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.	LOWER
CIP-007-1	R2.1.	The Responsible Entity shall enable only those ports and services required for normal and emergency operations.	MEDIUM
CIP-007-1	R2.2.	The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).	MEDIUM
CIP-007-1	R2.3.	In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	LOWER
CIP-007-1	R3.	Security Patch Management — The Responsible Entity, either separately or as a component of the documented configuration management process specified in CIP-003 Requirement R6, shall establish and document a security patch management program for tracking, evaluating, testing, and installing applicable cyber security software patches for all Cyber Assets within the Electronic Security Perimeter(s).	LOWER
CIP-007-1	R3.1.	The Responsible Entity shall document the assessment of security patches and security upgrades for applicability within thirty calendar days of availability of the patches or upgrades.	LOWER
CIP-007-1	R3.2.	The Responsible Entity shall document the implementation of security patches. In any case where the patch is not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	LOWER
CIP-007-1	R4.	Malicious Software Prevention — The Responsible Entity shall use anti-virus software and other malicious software ("malware") prevention tools, where technically feasible, to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of	LOWER

CIP-007-1 — Systems Security Management			
		malware on all Cyber Assets within the Electronic Security Perimeter(s).	
CIP-007-1	R4.1.	The Responsible Entity shall document and implement anti-virus and malware prevention tools. In the case where anti-virus software and malware prevention tools are not installed, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.	LOWER
CIP-007-1	R4.2.	The Responsible Entity shall document and implement a process for the update of anti-virus and malware prevention “signatures.” The process must address testing and installing the signatures.	LOWER
CIP-007-1	R5.	Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.	LOWER
CIP-007-1	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of “need to know” with respect to work functions performed.	
CIP-007-1	R5.1.1.	The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003 Requirement R5.	LOWER
CIP-007-1	R5.1.2.	The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.	LOWER
CIP-007-1	R5.1.3.	The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003 Requirement R5 and Standard CIP-004 Requirement R4.	LOWER
CIP-007-1	R5.2.	The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.	LOWER
CIP-007-1	R5.2.1	The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.	LOWER
CIP-007-1	R5.2.2.	The Responsible Entity shall identify those individuals with access to shared accounts.	LOWER
CIP-007-1	R5.2.3.	Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).	LOWER
CIP-007-1	R5.3.	At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:	LOWER
CIP-007-1	R5.3.1	Each password shall be a minimum of six characters.	LOWER
CIP-007-1	R5.3.2	Each password shall consist of a combination of alpha, numeric,	LOWER

CIP-007-1 — Systems Security Management			
		and “special” characters.	
CIP-007-1	R5.3.3	Each password shall be changed at least annually, or more frequently based on risk.	
CIP-007-1	R6.	Security Status Monitoring — The Responsible Entity shall ensure that all Cyber Assets within the Electronic Security Perimeter, as technically feasible, implement automated tools or organizational process controls to monitor system events that are related to cyber security.	LOWER
CIP-007-1	R6.1.	The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for monitoring for security events on all Cyber Assets within the Electronic Security Perimeter.	LOWER
CIP-007-1	R6.2.	The security monitoring controls shall issue automated or manual alerts for detected Cyber Security Incidents.	LOWER
CIP-007-1	R6.3.	The Responsible Entity shall maintain logs of system events related to cyber security, where technically feasible, to support incident response as required in Standard CIP-008.	LOWER
CIP-007-1	R6.4.	The Responsible Entity shall retain all logs specified in Requirement R6 for ninety calendar days.	LOWER
CIP-007-1	R6.5.	The Responsible Entity shall review logs of system events related to cyber security and maintain records documenting review of logs.	LOWER
CIP-007-1	R7.	Disposal or Redeployment — The Responsible Entity shall establish formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005.	
CIP-007-1	R7.1.	Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	LOWER
CIP-007-1	R7.2.	Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.	LOWER
CIP-007-1	R7.3.	The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.	LOWER
CIP-007-1	R8.	Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of all Cyber Assets within the Electronic Security Perimeter at least annually. The vulnerability assessment shall include, at a minimum, the following:	LOWER
CIP-007-1	R8.1.	A document identifying the vulnerability assessment process;	LOWER
CIP-007-1	R8.2.	A review to verify that only ports and services required for operation of the Cyber Assets within the Electronic Security Perimeter are enabled;	LOWER
CIP-007-1	R8.3.	A review of controls for default accounts; and,	LOWER
CIP-007-1	R8.4.	Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.	LOWER

CIP-007-1 — Systems Security Management			
CIP-007-1	R9.	Documentation Review and Maintenance — The Responsible Entity shall review and update the documentation specified in Standard CIP-007 at least annually. Changes resulting from modifications to the systems or controls shall be documented within ninety calendar days of the change.	LOWER

CIP-008-1 — Incident Reporting and Response Planning			
CIP-008-1	R1.	Cyber Security Incident Response Plan — The Responsible Entity shall develop and maintain a Cyber Security Incident response plan. The Cyber Security Incident Response plan shall address, at a minimum, the following:	LOWER
CIP-008-1	R1.1.	Procedures to characterize and classify events as reportable Cyber Security Incidents.	LOWER
CIP-008-1	R1.2.	Response actions, including roles and responsibilities of incident response teams, incident handling procedures, and communication plans.	LOWER
CIP-008-1	R1.3.	Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES ISAC either directly or through an intermediary.	LOWER
CIP-008-1	R1.4.	Process for updating the Cyber Security Incident response plan within ninety calendar days of any changes.	LOWER
CIP-008-1	R1.5.	Process for ensuring that the Cyber Security Incident response plan is reviewed at least annually.	LOWER
CIP-008-1	R1.6.	Process for ensuring the Cyber Security Incident response plan is tested at least annually. A test of the incident response plan can range from a paper drill, to a full operational exercise, to the response to an actual incident.	LOWER
CIP-008-1	R2.	Cyber Security Incident Documentation — The Responsible Entity shall keep relevant documentation related to Cyber Security Incidents reportable per Requirement R1.1 for three calendar years.	LOWER

CIP-009-1 — Recovery Plans for Critical Cyber Assets			
CIP-009-1	R1.	Recovery Plans — The Responsible Entity shall create and annually review recovery plan(s) for Critical Cyber Assets. The recovery plan(s) shall address at a minimum the following:	MEDIUM
CIP-009-1	R1.1.	Specify the required actions in response to events or conditions of varying duration and severity that would activate the recovery plan(s).	MEDIUM
CIP-009-1	R1.2.	Define the roles and responsibilities of responders.	MEDIUM
CIP-009-1	R2.	Exercises — The recovery plan(s) shall be exercised at least annually. An exercise of the recovery plan(s) can range from a paper drill, to a full operational exercise, to recovery from an actual incident.	LOWER
CIP-009-1	R3.	Change Control — Recovery plan(s) shall be updated to reflect	LOWER

CIP-009-1 — Recovery Plans for Critical Cyber Assets			
		any changes or lessons learned as a result of an exercise or the recovery from an actual incident. Updates shall be communicated to personnel responsible for the activation and implementation of the recovery plan(s) within ninety calendar days of the change.	
CIP-009-1	R4.	Backup and Restore — The recovery plan(s) shall include processes and procedures for the backup and storage of information required to successfully restore Critical Cyber Assets. For example, backups may include spare electronic components or equipment, written documentation of configuration settings, tape backup, etc.	LOWER
CIP-009-1	R5.	Testing Backup Media — Information essential to recovery that is stored on backup media shall be tested at least annually to ensure that the information is available. Testing can be completed off site.	LOWER

Violation Risk Factors — Version 1 Standards Matrix

The following table lists the Violation Risk Factors (VRFs) for the requirements in the following Version 1 Emergency Operations, Transmission Operations, and Voltage Control standards:

EOP-005-1 — System Restoration Plans

TOP-002-2 — Normal Operations Planning

VAR-001-1 — Voltage and Reactive Control

VAR-002-1 — Generator Operations for Maintaining Network Voltage Schedules

These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the Version 1 VRF survey.

EOP-005-1 — System Restoration Plans			
EOP-005-1	R1.	Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.	MEDIUM
EOP-005-1	R10.	The Transmission Operator shall demonstrate, through simulation or testing, that the blackstart generating units in its restoration plan can perform their intended functions as required in the regional restoration plan.	MEDIUM
EOP-005-1	R10.1.	The Transmission Operator shall perform this simulation or testing at least once every five years.	MEDIUM
EOP-005-1	R11.	Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.	HIGH
EOP-005-1	R11.1.	The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).	MEDIUM
EOP-005-1	R11.2.	The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.	HIGH
EOP-005-1	R11.3.	The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.	HIGH
EOP-005-1	R11.4.	The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.	HIGH
EOP-005-1	R11.5.	The affected Transmission Operators may resynchronize the	MEDIUM

EOP-005-1 — System Restoration Plans			
		isolated area(s) with the surrounding area(s) when the following conditions are met:	
EOP-005-1	R11.5.1.	Voltage, frequency, and phase angle permit.	HIGH
EOP-005-1	R11.5.2.	The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.	HIGH
EOP-005-1	R11.5.3.	Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.	MEDIUM
EOP-005-1	R11.5.4.	Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.	HIGH
EOP-005-1	R2.	Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.	MEDIUM
EOP-005-1	R3.	Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.	MEDIUM
EOP-005-1	R4.	Each Transmission Operator shall coordinate its restoration plans with the Generator Owners and Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.	MEDIUM
EOP-005-1	R5.	Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.	MEDIUM
EOP-005-1	R6.	Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.	MEDIUM
EOP-005-1	R7.	Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.	MEDIUM
EOP-005-1	R8.	Each Transmission Operator shall verify that the number, size, availability, and location of system blackstart generating units are sufficient to meet Regional Reliability Organization restoration plan requirements for the Transmission Operator's area.	MEDIUM
EOP-005-1	R9.	The Transmission Operator shall document the Cranking Paths, including initial switching requirements, between each blackstart generating unit and the unit(s) to be started and shall provide this documentation for review by the Regional Reliability Organization upon request. Such documentation may include Cranking Path diagrams.	MEDIUM

TOP-002-2 — Normal Operations Planning			
TOP-002-2	R14	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:	MEDIUM
TOP-002-2	R14.1	Changes in real output capabilities.	MEDIUM

VAR-001-1 — Voltage and Reactive Control			
VAR-001-1	R3	The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.	LOWER
VAR-001-1	R3.1	Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.	LOWER
VAR-001-1	R3.2	For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.	LOWER
VAR-001-1	R4	Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).	MEDIUM
VAR-001-1	R6.1	When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.	MEDIUM
VAR-001-1	R11	After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.	LOWER

VAR-002-1 — Generator Operations for Maintaining Network Voltage Schedules			
VAR-002-1	R1	The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.	MEDIUM
VAR-002-1	R2	Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.	MEDIUM
VAR-002-1	R2.1	When a generator’s automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.	MEDIUM
VAR-002-1	R2.2	When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.	MEDIUM
VAR-002-1	R3	Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:	MEDIUM
VAR-002-1	R3.1	A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator	MEDIUM

VAR-002-1 — Generator Operations for Maintaining Network Voltage Schedules			
		and power system stabilizer and the expected duration of the change in status or capability.	
VAR-002-1	R3.2	A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.	MEDIUM
VAR-002-1	R4	The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.	LOWER
VAR-002-1	R4.1	For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:	LOWER
VAR-002-1	R4.1.1	Tap settings.	LOWER
VAR-002-1	R4.1.2	Available fixed tap ranges.	LOWER
VAR-002-1	R4.1.3	Impedance data.	LOWER
VAR-002-1	R4.1.4	The +/- voltage range with step-change in % for load-tap changing transformers.	LOWER
VAR-002-1	R5	After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.	MEDIUM
VAR-002-1	R5.1	If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.	LOWER

Violation Risk Factors — Version 1 Standards Matrix

The following table lists the Violation Risk Factors (VRFs) for the requirements in the following Version 1 Facility Ratings standards:

FAC-008-1 — Facility Ratings Methodology
FAC-009-1 — Establish and Communicate Facility Ratings
FAC-010-1 — System Operating Limits Methodology for the Planning Horizon
FAC-011-1 — System Operating Limits Methodology for the Operations Horizon
FAC-012-1 — Transfer Capabilities Methodology
FAC-013-1 — Establish and Communicate Transfer Capabilities
FAC-014-1 — Establish and Communicate System Operating Limits

These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the Version 1 VRF survey.

FAC-008-1 — Facility Ratings Methodology			
FAC-008-1	R1.	The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:	LOWER
FAC-008-1	R1.1.	A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.	LOWER
FAC-008-1	R1.2.	The method by which the Rating (of major BES equipment that comprises a Facility) is determined.	LOWER
FAC-008-1	R1.2.1.	The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.	LOWER
FAC-008-1	R1.2.2.	The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.	LOWER
FAC-008-1	R1.3.	Consideration of the following:	LOWER
FAC-008-1	R1.3.1.	Ratings provided by equipment manufacturers.	MEDIUM
FAC-008-1	R1.3.2.	Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer’s warranty, IEEE, ANSI or other standards).	MEDIUM
FAC-008-1	R1.3.3.	Ambient conditions.	MEDIUM
FAC-008-1	R1.3.4.	Operating limitations.	MEDIUM
FAC-008-1	R1.3.5.	Other assumptions.	LOWER
FAC-008-1	R2.	The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.	LOWER
FAC-008-1	R3.	If a Reliability Coordinator, Transmission Operator, Transmission	LOWER

FAC-008-1 — Facility Ratings Methodology			
		Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.	

FAC-009-1 — Establish and Communicate Facility Ratings			
FAC-009-1	R1.	The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.	MEDIUM
FAC-009-1	R2.	The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.	MEDIUM

FAC-010-1 — System Operating Limits Methodology for the Planning Horizon			
FAC-010-1	R1	The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	LOWER
FAC-010-1	R1.1	Be applicable for developing SOLs used in the planning horizon.	LOWER
FAC-010-1	R1.2	State that SOLs shall not exceed associated Facility Ratings.	LOWER
FAC-010-1	R1.3	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER
FAC-010-1	R2	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	LOWER
FAC-010-1	R2.1	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	MEDIUM
FAC-010-1	R2.2	Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.	MEDIUM
FAC-010-1	R2.2.1	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM

FAC-010-1 — System Operating Limits Methodology for the Planning Horizon			
FAC-010-1	R2.2.2	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM
FAC-010-1	R2.2.3	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM
FAC-010-1	R2.3	Starting with all Facilities in service, the system’s response to a single Contingency may include any of the following:	MEDIUM
FAC-010-1	R2.3.1	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	MEDIUM
FAC-010-1	R2.3.2	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	MEDIUM
FAC-010-1	R2.4	Starting with all facilities in service, the system’s response to one of the multiple Contingencies identified in Reliability Standard TPL-003, the system shall demonstrate dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.	MEDIUM
FAC-010-1	R2.5	In determining the system’s response to a multiple Contingency, the following shall be acceptable:	MEDIUM
FAC-010-1	R2.5.1	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers	MEDIUM
FAC-010-1	R3	The Planning Authority’s SOL methodology, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	LOWER
FAC-010-1	R3.1.	Area of study (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	LOWER
FAC-010-1	R3.2.	Selection of applicable Contingencies.	LOWER
FAC-010-1	R3.3.	Level of detail of system models used to determine SOLs.	LOWER
FAC-010-1	R3.4	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM
FAC-010-1	R3.5	Anticipated transmission system configuration, generation dispatch and Load level.	LOWER
FAC-010-1	R3.6	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tv.	LOWER
FAC-010-1	R4	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:	LOWER
FAC-010-1	R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	LOWER
FAC-010-1	R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority’s Planning Authority	LOWER

FAC-010-1 — System Operating Limits Methodology for the Planning Horizon			
		Area.	
FAC-010-1	R4.3.	Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	LOWER
FAC-010-1	R5	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why.	LOWER

FAC-011-1 — System Operating Limits Methodology for the Operations Horizon			
FAC-011-1	R1	The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	LOWER
FAC-011-1	R1.1	Be applicable for developing SOLs used in the operations horizon.	LOWER
FAC-011-1	R1.2	State that SOLs shall not exceed associated Facility Ratings.	LOWER
FAC-011-1	R1.3	Include a description of how to identify the subset of SOLs that qualify as IROLs.	LOWER
FAC-011-1	R2	The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:	MEDIUM
FAC-011-1	R2.1	In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	MEDIUM
FAC-011-1	R2.2	Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading Outages or uncontrolled separation shall not occur.	MEDIUM
FAC-011-1	R2.2.1	Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	MEDIUM
FAC-011-1	R2.2.2	Loss of any generator, line, transformer, or shunt device without a Fault.	MEDIUM
FAC-011-1	R2.2.3	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	MEDIUM
FAC-011-1	R2.3	In determining the system's response to a single Contingency, the following shall be acceptable:	MEDIUM
FAC-011-1	R2.3.1	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	MEDIUM
FAC-011-1	R2.3.2	Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one	MEDIUM

FAC-011-1 — System Operating Limits Methodology for the Operations Horizon			
		prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied.	
FAC-011-1	R2.3.3	System reconfiguration through manual or automatic control or protection actions.	MEDIUM
FAC-011-1	R2.4	To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.	MEDIUM
FAC-011-1	R3	The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	MEDIUM
FAC-011-1	R3.1.	Area of study (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	MEDIUM
FAC-011-1	R3.2.	Selection of applicable Contingencies.	MEDIUM
FAC-011-1	R3.3.	A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for real-time use given the real-time system conditions. The process shall address recalculating these stability limits and expanding this list of stability limits and the list of stability-related multiple contingencies.	MEDIUM
FAC-011-1	R3.4	Level of detail of system models used to determine SOLs.	
FAC-011-1	R3.5	Allowed uses of Special Protection Systems or Remedial Action Plans.	MEDIUM
FAC-011-1	R3.6	Anticipated transmission system configuration, generation dispatch and Load level.	MEDIUM
FAC-011-1	R3.7	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL Tv.	MEDIUM
FAC-011-1	R4	The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:	LOWER
FAC-011-1	R4.1.	Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	LOWER
FAC-011-1	R4.2.	Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator’s Reliability Coordinator Area.	LOWER
FAC-011-1	R4.3.	Each Transmission Operator that operates in the Reliability Coordinator Area.	LOWER
FAC-011-1	R5	If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL	LOWER

FAC-011-1 — System Operating Limits Methodology for the Operations Horizon			
		Methodology and, if no change will be made to that SOL Methodology, the reason why.	

FAC-012-1 — Transfer Capabilities Methodology			
FAC-012-1	R1.	The Reliability Coordinator and Planning Authority shall each document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). The Transfer Capability Methodology shall include all of the following:	LOWER
FAC-012-1	R1.1.	A statement that Transfer Capabilities shall respect all applicable System Operating Limits (SOLs).	LOWER
FAC-012-1	R1.2.	A definition stating whether the methodology is applicable to the planning horizon or the operating horizon.	
FAC-012-1	R1.3.	A description of how each of the following is addressed, including any reliability margins applied to reflect uncertainty with projected BES conditions:	LOWER
FAC-012-1	R1.3.1.	Transmission system topology	LOWER
FAC-012-1	R1.3.2.	System demand	LOWER
FAC-012-1	R1.3.3.	Generation dispatch	LOWER
FAC-012-1	R1.3.4.	Current and projected transmission uses	LOWER
FAC-012-1	R2.	The Reliability Coordinator shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:	LOWER
FAC-012-1	R2.1	Each Adjacent Reliability Coordinator and each Reliability Coordinator that indicated a reliability-related need for the methodology.	LOWER
FAC-012-1	R2.2	Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	
FAC-012-1	R2.3	Each Transmission Operator that operates in the Reliability Coordinator Area.	LOWER
FAC-012-1	R3.	The Planning Authority shall issue its Transfer Capability Methodology, and any changes to that methodology, prior to the effectiveness of such changes, to all of the following:	LOWER
FAC-012-1	R3.1.	Each Transmission Planner that works in the Planning Authority's Planning Authority Area.	LOWER
FAC-012-1	R3.2.	Each Adjacent Planning Authority and each Planning Authority that indicated a reliability-related need for the methodology.	LOWER
FAC-012-1	R3.3.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	LOWER
FAC-012-1	R4.	If a recipient of the Transfer Capability Methodology provides documented technical comments on the methodology, the Reliability Coordinator or Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability Methodology and,	LOWER

FAC-012-1 — Transfer Capabilities Methodology			
		if no change will be made to that Transfer Capability Methodology, the reason why.	

FAC-013-1 — Establish and Communicate Transfer Capabilities			
FAC-013-1	R1.	The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.	MEDIUM
FAC-013-1	R2.	The Reliability Coordinator and Planning Authority shall each provide its inter-regional and intra-regional Transfer Capabilities to those entities that have a reliability-related need for such Transfer Capabilities and make a written request that includes a schedule for delivery of such Transfer Capabilities as follows:	MEDIUM
FAC-013-1	R2.1.	The Reliability Coordinator shall provide its Transfer Capabilities to its associated Regional Reliability Organization(s), to its adjacent Reliability Coordinators, and to the Transmission Operators, Transmission Service Providers and Planning Authorities that work in its Reliability Coordinator Area.	MEDIUM
FAC-013-1	R2.2.	The Planning Authority shall provide its Transfer Capabilities to its associated Reliability Coordinator(s) and Regional Reliability Organization(s), and to the Transmission Planners and Transmission Service Provider(s) that work in its Planning Authority Area.	MEDIUM

FAC-014-1 — Establish and Communicate System Operating Limits			
FAC-014-1	R1	The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	MEDIUM
FAC-014-1	R2	The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator’s SOL Methodology.	MEDIUM
FAC-014-1	R3	The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology.	MEDIUM
FAC-014-1	R4	The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority’s SOL Methodology.	MEDIUM
FAC-014-1	R5	The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:	MEDIUM
FAC-014-1	R5.1	The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability	MEDIUM

FAC-014-1 — Establish and Communicate System Operating Limits			
		Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	
FAC-014-1	R5.1.1	Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL.	MEDIUM
FAC-014-1	R5.1.2	The value of the IROL and its associated Tv.	MEDIUM
FAC-014-1	R5.1.3	The associated Contingency(ies).	MEDIUM
FAC-014-1	R5.1.4	The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	MEDIUM
FAC-014-1	R5.2	The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	MEDIUM
FAC-014-1	R5.3	The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.	MEDIUM
FAC-014-1	R5.4	The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	MEDIUM
FAC-014-1	R6	The Planning Authority shall identify the subset of multiple contingencies from Reliability Standard TPL-003 which result in stability limits.	MEDIUM
FAC-014-1	R6.1	The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.	MEDIUM

Violation Risk Factors — Version 1 Standards Matrix

The following table lists the Violation Risk Factors (VRFs) for the requirements in the following Version 1 Interconnection Reliability Operations standards:

IRO-014-1 — Procedures to Support Coordination Between Reliability Coordinators
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators

These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the Version 1 VRF survey.

IRO-014-1 — Procedures to Support Coordination Between Reliability Coordinators			
IRO-014-1	R1.	The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.	MEDIUM
IRO-014-1	R1.1.	These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:	LOWER
IRO-014-1	R1.1.1.	Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators. Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren't limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of special protection systems, etc.	MEDIUM
IRO-014-1	R1.1.2.	Energy and capacity shortages.	MEDIUM
IRO-014-1	R1.1.3.	Planned or unplanned outage information.	MEDIUM
IRO-014-1	R1.1.4.	Voltage control, including the coordination of reactive resources for voltage control.	MEDIUM
IRO-014-1	R2.	Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:	LOWER
IRO-014-1	R2.1.	Agreed to by all the Reliability Coordinators required to take the indicated action(s).	LOWER
IRO-014-1	R2.2.	Distributed to all Reliability Coordinators that are required to take the indicated action(s).	LOWER
IRO-014-1	R3.	A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:	

IRO-014-1 — Procedures to Support Coordination Between Reliability Coordinators			
IRO-014-1	R3.1.	A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	MEDIUM
IRO-014-1	R3.2.	The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.	LOWER
IRO-014-1	R4.	Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:	LOWER
IRO-014-1	R4.1.	Include version control number or date	LOWER
IRO-014-1	R4.2.	Include a distribution list.	LOWER
IRO-014-1	R4.3.	Be reviewed, at least once every three years, and updated if needed.	LOWER
IRO-014-7	R1.1.5.	Coordination of information exchange to support reliability assessments.	LOWER
IRO-014-8	R1.1.6.	Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.	LOWER

IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators			
IRO-015-1	R1.	The Reliability Coordinator shall follow its Operating Procedures, Processes, or Plans for making notifications and exchanging reliability-related information with other Reliability Coordinators.	MEDIUM
IRO-015-1	R1.1.	The Reliability Coordinator shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.	MEDIUM
IRO-015-1	R2.	The Reliability Coordinator shall participate in agreed upon conference calls and other communication forums with adjacent Reliability Coordinators.	LOWER
IRO-015-1	R2.1.	The frequency of these conference calls shall be agreed upon by all involved Reliability Coordinators and shall be at least weekly.	LOWER
IRO-015-1	R3.	The Reliability Coordinator shall provide reliability-related information as requested by other Reliability Coordinators.	MEDIUM

IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators			
IRO-016-1	R1.	The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.	MEDIUM
IRO-016-1	R1.1.	If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.	MEDIUM
IRO-016-1	R1.2.	If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the	MEDIUM

IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators			
		causes of the disagreement (bad data, status, study results, tools, etc.).	
IRO-016-1	R1.2.1.	If time permits, this re-evaluation shall be done before taking corrective actions.	MEDIUM
IRO-016-1	R1.2.2.	If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.	MEDIUM
IRO-016-1	R1.3.	If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.	MEDIUM
IRO-016-1	R2.	The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.	LOWER

Violation Risk Factors — Version 1 Standards Matrix

The following table lists the Violation Risk Factors (VRFs) for the requirements in the following Version 1 Modeling standards:

MOD-013 — Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures

MOD-016 — Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-side Management

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

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

These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the Version 1 VRF survey.

MOD-013 — Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures			
MOD-013-1	R1.	The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements:	MEDIUM
MOD-013-1	R1.1.	Design data shall be provided for new or refurbished excitation systems (for synchronous generators and synchronous condensers) at least three months prior to the installation date.	MEDIUM
MOD-013-1	R1.1.1.	If design data is unavailable from the manufacturer 3 months prior to the installation date, estimated or typical manufacturer's data, based on excitation systems of similar design and characteristics, shall be provided.	LOWER
MOD-013-1	R1.2.	Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.	MEDIUM
MOD-013-1	R1.2.1.	Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.	MEDIUM
MOD-013-1	R1.2.2.	The Interconnection-wide requirements shall specify unit size thresholds for permitting: The use of non-detailed vs. detailed models, The netting of small generating units with bus load, and	LOWER

MOD-013 — Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures			
		The combining of multiple generating units at one plant.	
MOD-013-1	R1.3.	Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.	MEDIUM
MOD-013-1	R1.4.	Dynamics data representing electrical Demand characteristics as a function of frequency and voltage.	LOWER
MOD-013-1	R1.5.	Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Reliability Standard MOD-010 Requirement 1.	MEDIUM
MOD-013-1	R2.	The Regional Reliability Organization shall participate in the documentation of its Interconnection’s data requirements and reporting procedures and, shall participate in the review of those data requirements and reporting procedures (at least every five years), and shall provide those data requirements and reporting procedures to Regional Reliability Organizations, NERC, and all users of the Interconnected systems on request (within five business days).	LOWER

MOD-016 — Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-side Management			
MOD-016-1	R1.	The Planning Authority and Regional Reliability Organization shall have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.	LOWER
MOD-016-1	R1.1.	The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. The data submittal requirements shall stipulate that each Load-Serving Entity count its customer Demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer Demand values.	LOWER
MOD-016-1	R2.	The Regional Reliability Organization shall distribute its documentation required in Requirement 1 and any changes to that documentation, to all Planning Authorities that work within its Region. the Regional Reliability Organization shall make this distribution within 30 calendar days of approval. The Planning Authority shall distribute its documentation required in R1 for reporting customer data and any changes to that documentation, to its Transmission Planners and Load-Serving Entities that work within its Planning Authority Area. The Planning Authority shall make this distribution within 30 calendar days of approval.	LOWER

MOD-024 — Verification of Generator Gross and Net Real Power Capability			
MOD-024-1	R1.	The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Real Power capability. These procedures shall include the following:	MEDIUM
MOD-024-1	R1.1.	Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	MEDIUM
MOD-024-1	R1.2.	Criteria for reporting generating unit auxiliary loads.	LOWER
MOD-024-1	R1.3.	Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, and testing, etc.	MEDIUM
MOD-024-1	R1.4.	Periodicity and schedule of model and data verification and reporting.	MEDIUM
MOD-024-1	R1.5.	Information to be verified and reported:	MEDIUM
MOD-024-1	R1.5.1.	Seasonal gross and net Real Power generating capabilities.	MEDIUM
MOD-024-1	R1.5.2.	Real power requirements of auxiliary loads.	LOWER
MOD-024-1	R1.5.3.	Method of verification, including date and conditions.	MEDIUM
MOD-024-1	R2.	The Regional Reliability Organization shall provide its generator gross and net Real Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	LOWER
MOD-024-1	R3.	The Generator Owner shall follow its Regional Reliability Organization’s procedures for verifying and reporting its gross and net Real Power generating capability per R1.	MEDIUM

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability			
MOD-025-1	R1.	The Regional Reliability Organization shall establish and maintain procedures to address verification of generator gross and net Reactive Power capability. These procedures shall include the following:	LOWER
MOD-025-1	R1.1.	Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.	LOWER
MOD-025-1	R1.2.	Criteria for reporting generating unit auxiliary loads.	LOWER
MOD-025-1	R1.3.	Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of commissioning data, performance tracking, engineering analysis, testing, etc.	LOWER
MOD-025-1	R1.4.	Periodicity and schedule of model and data verification and reporting.	LOWER
MOD-025-1	R1.5.	Information to be reported:	LOWER
MOD-025-1	R1.5.1.	Verified maximum gross and net Reactive Power capability (both lagging and leading) at Seasonal Real Power generating	LOWER

MOD-025 — Verification of Generator Gross and Net Reactive Power Capability			
		capabilities as reported in accordance with Reliability Standard MOD-024 Requirement 1.5.1.	
MOD-025-1	R1.5.2.	Verified Reactive Power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc.	LOWER
MOD-025-1	R1.5.2.	Verified Reactive Power of auxiliary loads.	LOWER
MOD-025-1	R1.5.4.	Method of verification, including date and conditions.	LOWER
MOD-025-1	R2.	The Regional Reliability Organization shall provide its generator gross and net Reactive Power capability verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.	LOWER
MOD-025-1	R3.	The Generator Owner shall follow its Regional Reliability Organization’s procedures for verifying and reporting its gross and net Reactive Power generating capability per R1.	LOWER

Violation Risk Factors — Version 1 Standards Matrix

The following table lists the Violation Risk Factors (VRFs) for the requirements in the following Version 1 Protection and Control standards:

PRC-002-1 — Define and Document Disturbance Monitoring Equipment Requirements

PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-021-1 — Under-Voltage Load Shedding Program Data

PRC-022-1 — Under-Voltage Load Shedding Program Performance

These VRFs are the weighted average of the stakeholder VRF selections from the second posting of the Version 1 VRF survey.

PRC-002-1 — Define and Document Disturbance Monitoring Equipment Requirements			
PRC-002-1	R1	The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:	LOWER
PRC-002-1	R1.1	Location, monitoring and recording requirements, including the following:	LOWER
PRC-002-1	R1.1.1.	Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).	LOWER
PRC-002-1	R1.1.2.	Devices to be monitored.	LOWER
PRC-002-1	R2	The Regional Reliability Organization shall establish the following installation requirements for fault recording:	LOWER
PRC-002-1	R2.1	Location, monitoring and recording requirements, including the following:	LOWER
PRC-002-1	R2.1.1	Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).	LOWER
PRC-002-1	R2.1.2	Elements to be monitored at each location.	LOWER
PRC-002-1	R2.1.3	Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:	LOWER
PRC-002-1	R2.1.3.1	Three phase to neutral voltages.	LOWER
PRC-002-1	R2.1.3.2	Three phase currents and neutral currents.	LOWER
PRC-002-1	R2.1.3.3	Polarizing currents and voltages, if used.	LOWER
PRC-002-1	R2.1.3.4	Frequency.	LOWER
PRC-002-1	R2.1.3.5	Megawatts and megavars.	LOWER
PRC-002-1	R2.2	Technical requirements, including the following:	LOWER
PRC-002-1	R2.2.1	Recording duration requirements.	LOWER
PRC-002-1	R2.2.2	Minimum sampling rate of 16 samples per cycle.	LOWER
PRC-002-1	R2.2.3	Event triggering requirements.	LOWER
PRC-002-1	R3	The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording:	LOWER
PRC-002-1	R3.1.	Location, monitoring and recording requirements including the following:	LOWER
PRC-002-1	R3.1.1	Criteria for equipment location giving consideration to the following:	LOWER

PRC-002-1 — Define and Document Disturbance Monitoring Equipment Requirements			
		- Site(s) in or near major load centers - Site(s) in or near major generation clusters - Site(s) in or near major voltage sensitive areas - Site(s) on both sides of major transmission interfaces - A major transmission junction - Elements associated with Interconnection Reliability Operating Limits - Major EHV interconnections between control areas - Coordination with neighboring regions within the interconnection	
PRC-002-1	R3.1.2	Elements and number of phases to be monitored at each location.	LOWER
PRC-002-1	R3.1.3	Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:	LOWER
PRC-002-1	R3.1.3.1	Voltage, current and frequency.	LOWER
PRC-002-1	R3.1.3.2	Megawatts and megavars.	LOWER
PRC-002-1	R3.2.	Technical requirements, including the following:	LOWER
PRC-002-1	R3.2.1	Capability for continuous recording for devices installed after January 1, 2009.	LOWER
PRC-002-1	R3.2.2	Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	LOWER
PRC-002-1	R4	The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:	LOWER
PRC-002-1	R4.1.	Criteria for events that require the collection of data from DMEs.	LOWER
PRC-002-1	R4.2.	List of entities that must be provided with recorded Disturbance data.	LOWER
PRC-002-1	R4.3.	Timetable for response to data request.	LOWER
PRC-002-1	R4.4	Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE[1] analysis tool,	LOWER
PRC-002-1	R4.5	Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files[2].	LOWER
PRC-002-1	R4.6	Data content requirements and guidelines.	LOWER
PRC-002-1	R5	The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	LOWER
PRC-002-1	R6	The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	LOWER

PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting			
PRC-018-1	R1	Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:	LOWER
PRC-018-1	R1.1	Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	LOWER
PRC-018-1	R1.2	Recorded data from each Disturbance shall be retrievable for ten calendar days..	LOWER
PRC-018-1	R2	The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).	LOWER
PRC-018-1	R3	The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):	LOWER
PRC-018-1	R3.1	Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).	LOWER
PRC-018-1	R3.2	Make and model of equipment.	LOWER
PRC-018-1	R3.3	Installation location.	LOWER
PRC-018-1	R3.4	Operational status.	LOWER
PRC-018-1	R3.5	Date last tested.	LOWER
PRC-018-1	R3.6	Monitored elements, such as transmission circuit, bus section, etc.	LOWER
PRC-018-1	R3.7	Monitored devices, such as circuit breaker, disconnect status, alarms, etc.	LOWER
PRC-018-1	R3.8	Monitored electrical quantities, such as voltage, current, etc.	LOWER
PRC-018-1	R4	The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).	LOWER
PRC-018-1	R5	The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	LOWER
PRC-018-1	R6	Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	LOWER
PRC-018-1	R6.1	Maintenance and testing intervals and their basis.	LOWER
PRC-018-1	R6.2	Summary of maintenance and testing procedures.	LOWER

PRC-021-1 — Under-Voltage Load Shedding Program Data			
PRC-021-1	R1.	Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:	LOWER
PRC-021-1	R1.1.	Size and location of customer load, or percent of connected load, to be interrupted.	LOWER
PRC-021-1	R1.2.	Corresponding voltage set points and overall scheme clearing times.	LOWER
PRC-021-1	R1.3.	Time delay from initiation to trip signal.	LOWER
PRC-021-1	R1.4.	Breaker operating times.	LOWER
PRC-021-1	R1.5.	Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Special Protection Systems.	LOWER
PRC-021-1	R2.	Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.	LOWER

PRC-022-1 — Under-Voltage Load Shedding Program Performance			
PRC-022-1	R1.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:	LOWER
PRC-022-1	R1.1.	A description of the event including initiating conditions.	LOWER
PRC-022-1	R1.2.	A review of the UVLS set points and tripping times.	LOWER
PRC-022-1	R1.3.	A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.	LOWER
PRC-022-1	R1.4.	A summary of the findings.	LOWER
PRC-022-1	R1.5.	For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.	MEDIUM
PRC-022-1	R2.	Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request.	LOWER

Exhibit C

Record of Development

(Available Upon Request)

Exhibit D

Standards Drafting Team Roster

Violation Risk Factors Drafting Team

Chairman	Stanley E. Kopman Director, Planning & Compliance	Northeast Power Coordinating Council 1515 Broadway 43rd Floor New York, New York 10036-8901	(212) 840-1070 (212) 302-2782 Fx skopman@npcc.org
NERC Staff	Timothy Kucey Manager of Enforcement & Mitigation	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx tim.kucey@ nerc.net
	Terry Bilke Technical Manager	Midwest ISO, Inc. 701 City Center Drive Carmel, Indiana 46032	(317) 249-5463 (317) 249-5910 Fx tbilke@ midwestiso.org
	Shannon Black	Sacramento Municipal Utility District 6301 S Street Sacramento, California 95817	(916) 732-5734 sblack@smud.org
	Cary B. Deise Director, Transmission Operations and Planning	Arizona Public Service Co. M.S. 2260 P.O. Box 53999 Phoenix, Arizona 85072-3999	(602) 250-1232 (602) 250-1155 Fx cary.deise@ aps.com
	Rod C. Hardiman Project Manager, Reliability & Risk Analysis Group Transmission Planning	Southern Company Services, Inc. 600 N. 18th Street P.O. Box 2641 Birmingham, Alabama 35291	(205) 257-7056 (205) 257-1040 Fx rchardim@ southernco.com
	Douglas F. Johnson Compliance Officer	American Transmission Company, LLC N19 W23993 Ridgeview Parkway West P.O. Box 47 Waukesha, Wisconsin 53188	(262) 506-6863 dfjohnson@ atcllc.com
	Richard J. Kafka Transmission Policy Manager	Potomac Electric Power Co. P.O. Box 341010 Bethesda, Maryland 3410120827-1010	(301) 469-5274 (301) 469-5235 Fx rjkafka@ pepcoholdings.com
	Joseph J. Krupar Operations Consultant	Florida Municipal Power Agency 8553 Commodity Circle Orlando, Florida 32819-9002	(407) 355-5793 (407) 355-5793 Fx joe.krupar@ fmpa.com
	Greg Lange Chief Dispatcher	Grant County PUD No. 2 P.O. Box 878 Ephrata, Washington 98823	(509) 754-5061 (509) 754-5392 Fx glange@gcpud.org
	Norbert D. Mizwicki Senior Consultant - Operations	ReliabilityFirst Corporation 939 Parkview Boulevard Lombard, Illinois 60148-3267	(630) 261-2657 (630) 691-4222 Fx norb.mizwicki@ rfirst.org

	Jim R. Nickel Senior Engineer	Michigan Public Power Agency 809 Centennial Way Lansing, Michigan 48917	(517) 323-8919 (517) 323-8373 Fx jnickel@ mpower.org
	Eric Senkowicz	Florida Reliability Coordinating Council 1408 N. Westshore Blvd Suite 1002 Tampa, Florida 33607	(813) 289-5644 esenkowicz@ frcc.com
	Philip Scott Sobol Senior Corporate Security Consultant	Corporate Risk Solutions, Inc. 8725 Rosehill Rd Lenexa, Kansas 66215	(913) 322-5402 psobol@ corprisk.net
SAC Liason	James Spearman Executive Assistant & Senior Technical Advisor	Public Service Commission of South Carolina 101 Executive Center Drive Suite 100 P.O. Drawer 11649 Columbia, South Carolina 29211	(803) 896-5142 (803) 896-5231 Fx james.spearman@ psc.sc.gov
	James R. Stanton Director of Reliability Compliance	Calpine Corporation 4100 Underwood Road Pasadena, Texas 77507	(832) 476-4453 (281) 291-7089 Fx jstanton@ calpine.com
	Gerald Steffens Manager of Operations/Reliability	Rochester Public Utilities	(507) 280-1607 (507) 280-1542 Fx gsteffens@ rpu.org
	John C. Stephens	FirstEnergy Corp. 76 South Main Street Akron, Ohio 44308	(330) 384-5356 stephensj@ firstenergycorp.com
	Charles V. Waits Vice President-Operations and Transmission Strategy	Michigan Electric Transmission Company 540 Avis Drive, Suite H Ann Arbor, Michigan 48108	(734) 929-1227 (734) 929-1212 Fx cwaits@ metcllc.com
	Joseph D. Willson Manager, Interregional Coordination & Compliance	PJM Interconnection, L.L.C. 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	(610) 666-8820 (610) 666-2296 Fx willsojd@pjm.com
NERC Staff	Craig Lawrence Standards Development Coordinator	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 craig.lawrence@ nerc.net
NERC Staff	Edward H. Ruck Regional Compliance Program Coordinator	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx ed.ruck@nerc.net
NERC Staff Coordinator	Richard Schneider Director of Standards Development	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx richard.schneider@ nerc.net