NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Version 0 Standards Drafting Team

May 20, 2004 — 8:00 a.m.– 5:00 p.m.
May 21, 2004 — 8:00 a.m.–noon
Four Points by Sheraton – Chicago O'Hare Airport

AGENDA

Agenda

1. **Administrative Items**
   a. Introductions, roster, and additional contacts (**Attachments 1 and 2**)
   b. Establishment of a quorum
   c. Meeting arrangements and protocols
   d. Election of officers
2. **Background Materials for Version 0 Standards Project**
   a. Standards transition plan (**Attachments 3 and 4**)
   b. Discussion of project objectives and timeline and role of drafting team
   c. Overview of operating policies, planning standards and compliance templates (**Attachment 5** to be sent under separate cover at a later date)
   d. Version 0 template for working drafts (**Attachment 6**)
   e. Compliance templates (**Attachments 7 and 8**)
   f. Operating manual http://www.nerc.com/~oc/opermanl.html
   g. Planning standards http://www.nerc.com/~filez/pss-psg.html
3. **Conversion of Operating Policies to Version 0 Standards**
   a. Preliminary drafts (**Attachment 9** – posted as a separate zip file)
   b. Interchange Authority issue (Operating Policy 3)
   c. Reliability Authority/Reliability Coordinator issue (Operating Policy 9)
   d. Potential business practices in operating policies
   e. Operating policy conversion – next steps and work assignments
4. **Conversion of Planning Standards to Version 0 Standards**
   a. Potential business practices in planning standards
   b. Planning standards conversion – next steps and work assignments
5. **Wrap Up**
   a. Review work assignments and timetable
   b. Future meetings and conference calls

Adjourn

Attachment 1

May 17, 2004

VERSION 0 STANDARDS DRAFTING TEAM ROSTER

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Plan for Accelerating the Adoption of NERC Reliability Standards

FINAL
April 19, 2004

Standards Transition Management Team

Standards Authorization Committee

Standards Transition Overview

This document describes a plan for accelerating the transition from existing NERC operating policies, planning standards and compliance templates to an integrated set of reliability standards by February 2005. The goal is to develop a "Version 0" baseline set of standards translated from the existing requirements and measures provided in:

- The April 2, 2004 Board-approved compliance templates.
- The existing operating policies, including modifications to Operating Policies 5, 6, and 9 made to address lessons learned from the August 14, 2003, blackout.
- The existing planning standards.

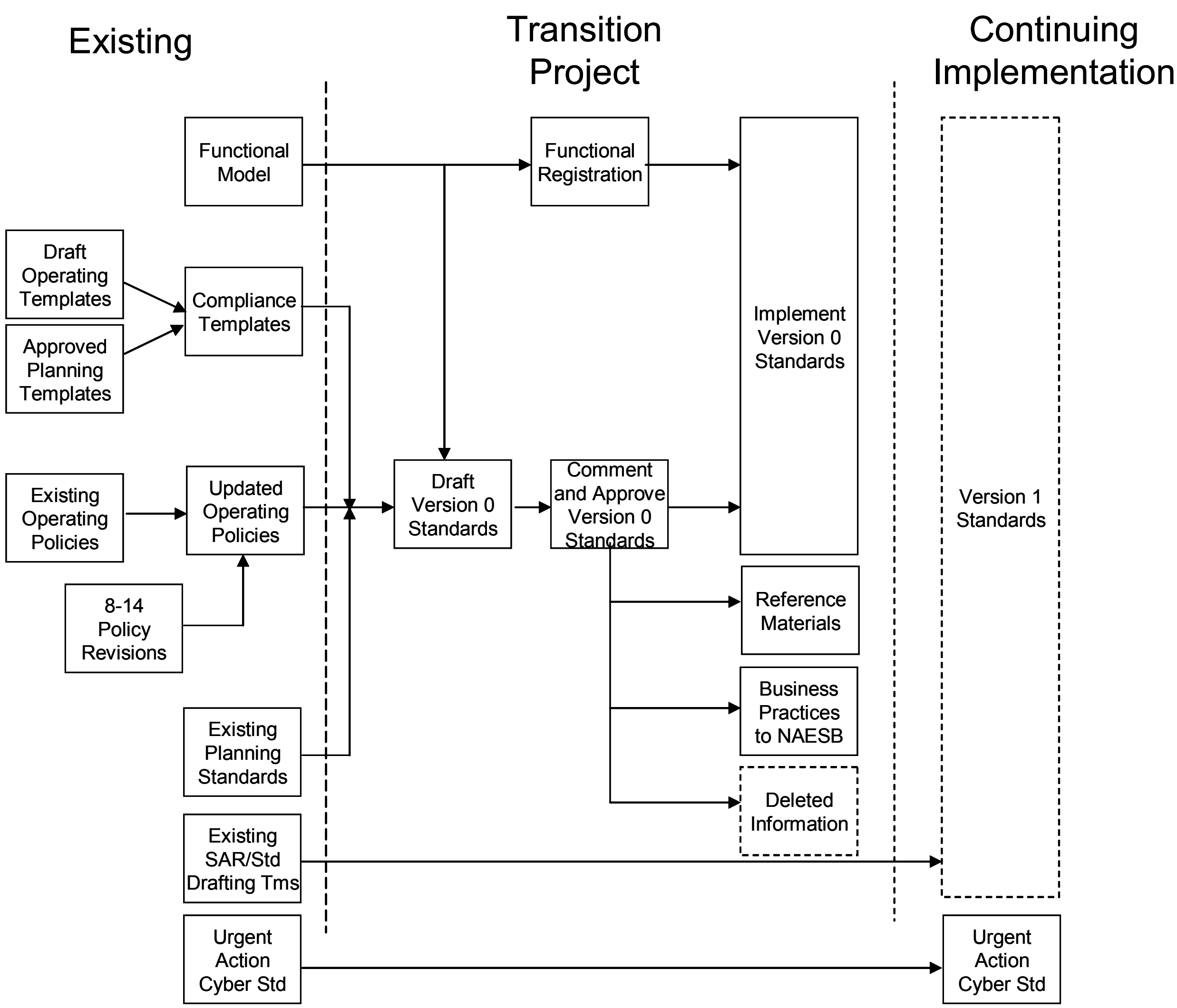


Figure 1 – Standards Transition Overview

In the drafting of the Version 0 standards, the Functional Model will be applied to designate functions to which each existing requirement and measure applies. In parallel, NERC and the

Regional Councils will seek to register all entities that perform the functions identified in the Version 0 standards.

The goal is to develop the Version 0 standards using the existing NERC Standards Process Manual. In the translation, portions of the existing reliability documents may be designated as Version 0 standards, potential business practice standards, reference materials, or may be subject to deletion.

Previously defined Standards Authorization Requests (SARs) and draft standards are expected to continue on their paths to adoption as Version 1 reliability standards, adding to or replacing the appropriate Version 0 standards subsequent to adoption of the Version 0 standards. The Urgent Action Cyber Security Standard (1200) is already a standard and is unaffected by the transition project.

A list of acronyms used in this plan is provided below for ease of reference.

ANSI	American National Standards Institute
BPRT	Business Practice Review Team
CCC	Compliance and Certification Committee
CCMC	Compliance and Certification Managers Committee
CIPC	Critical Infrastructure Protection Committee
DT	Drafting team
FERC	Federal Energy Regulatory Commission (FERC)
IRC	ISO/RTO Council
JIC	Joint Interface Committee
MC	Market Committee
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Council
OC	Operating Committee
PC	Planning Committee
SAC	Standards Authorization Committee
SAR	Standard Authorization Request
SPM	Standards Process Manual
STMT	Standards Transition Management Team
ST	Support Team

Background

In June 2002, the NERC Board of Trustees approved a new, consensus-based standards development procedure founded on the American National Standards Institute (ANSI) principles of openness, inclusiveness, balance, and fairness. On this basis, ANSI certified NERC as an ANSI standards developer in March 2003. NERC adopted the ANSI-based standards procedure primarily in response to a transformation of the industry that saw the reliability responsibilities of a finite set of vertically integrated utilities become unbundled to a more diverse spectrum of entities forming the market-based wholesale electric industry. The open standards process allows all parties responsible for, or impacted by, bulk electric system reliability to participate in the standards process.

The development of new reliability standards was initially conceived to start from a “clean slate”, rather than translating existing NERC operating policies and planning standards. A clean slate approach was preferred because it allowed better organization of the standards and necessitated establishing a logical reliability basis for proposing a standard rather than assuming continuation of ‘the way it has always been done’. There are currently 16 reliability standards in some stage of development: eleven originally proposed standards covering a minimum set of requirements for reliable planning and operation of bulk electric systems; four additional standards addressing certification criteria for reliability service providers; and a standard on cyber security adopted in August 2003 as an urgent action. Despite the progress to date, the development of reliability standards in the new process has been slower than initially expected.

Pending adoption of a minimum set of reliability standards, the NERC Operating Committee (OC) has continued to maintain its nine operating policies and associated appendices through the use of a transitional procedure. NERC also has 48 planning standards and 91 associated measures that were developed by the Planning Committee (PC). The concept until now for transitioning from existing operating policies and planning standards to new standards has been to adopt each new standard individually and retire appropriate sections of the existing documents, although a detailed plan was never developed and no standards have been transitioned in this manner.

The Functional Model was adopted by the NERC board initially in June 2001 and was revised in February 2004. The Functional Model provides a flexible framework for developing reliability standards in an unbundled industry in which the control area operated by a vertically integrated utility is no longer the sole entity responsible for reliability. Although the Functional Model has gained widespread acceptance conceptually, it has not yet seen significant application by NERC or the industry.

Need for Accelerating the Standards Transition

There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process:

1. The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable – now.

2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards."
3. An April 14, 2004 order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing "the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable."
4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources.
5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years.

The August 14, 2003 blackout has created an urgent need for NERC to ensure that its reliability standards are clear and measurable. This need has been reinforced by Recommendation 25 of the U.S./Canada Power System Outage Task Force and FERC's reliability policy objective, as noted above.

As an immediate step, the NERC board on April 2, 2004 adopted a set of 38 compliance templates to augment the existing operating policies and planning standards by clarifying some requirements and adding measures to be used in compliance audits. While not covering the complete set of operating policies and planning standards, the compliance templates address the most significant reliability issues to be reviewed during compliance evaluations. Additionally, the OC has proposed revisions to Operating Policies 5, 6 and 9 to clarify the responsibilities and authorities of control areas and reliability coordinators.

With the adoption of the compliance templates in April 2004, NERC now has four different sets of reliability documents: operating policies, planning standards, compliance templates, and emerging new reliability standards. Maintaining these documents creates an unnecessary burden on the industry of working in multiple forums and is an inefficient dilution of resources. In most cases, there has been a concerted effort to maintain a separation between standard drafting teams in the new process and the technical committees, resulting in multiple groups working on related topics. These demands are in addition to the need for the industry to participate in the development of business practice standards by the North American Energy Standards Board (NAESB).

The process for transferring to a new reliability standard and concurrently retiring applicable sections of the operating policies and planning standards was always recognized to be complex, particularly for the entities who must follow the reliability rules and the Regional Councils who are implementing the compliance programs. A protracted, multi-year transition would be confusing and more difficult than a more abbreviated effort to replace the operating policies and planning standards in a single step.

Objectives of the Accelerated Standards Transition

The goal of the accelerated standards transition project is to translate the existing NERC reliability rules, comprised of operating policies, planning standards, and compliance templates, into an integrated set of reliability standards, and to be positioned in February 2005 to move forward with one set of NERC standards administered through the ANSI-accredited process.

Specific objectives are to:

1. Translate the existing reliability rules – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the NERC board on April 2, and all approved revisions to Operating Policies 5, 6, and 9 being balloted in April 2004 – into an initial baseline (Version 0) set of reliability standards for adoption by the NERC Board at its February 8, 2005 meeting.
2. Identify the Functional Model designation for each performance requirement and measure in the Version 0 standards and determine, in concert with objective 3, whether to adopt the Functional Model designations into the Version 0 standards.
3. Complete an initial registration (not certification) of all functions identified in Version 0 standards by October 31, 2004.
4. In cooperation with NAESB and the ISO/RTO Council (IRC), and with the endorsement of the Joint Interface Committee (JIC) identify sections of the existing operating policies and planning standards that are suitable for NAESB to incorporate into their equivalent "Version 0" business practice standards.
5. Retire existing NERC operating policies, planning standards and compliance templates coincident with adoption of the Version 0 standards. Material that is not part of Version 0 standards will be made into NERC reference documents or NAESB business practices, or dropped if not needed.
6. Coordinate Version 0 standards development with the Compliance and Certification Committee (CCC) and Compliance and Certification Managers Committee (CCMC), to assist them in developing the compliance monitoring program for 2005 and beyond.
7. Support the continuing development of Version 1 reliability standards already in progress to become additions to or replacements of applicable sections of Version 0. Any new standards would be implemented subsequent to the adoption of Version 0.
8. Be prepared beginning in 2005 to consolidate the use of technical resources working in similar content areas (e.g. technical committees and drafting teams) to make more efficient use of resources in developing and revising standards.
9. Evaluate and improve the standards process so that it is responsive to reliability needs, while complying with the ANSI essential requirements.

Guiding Principles

The following principles are essential to the success of this project:

1. To expedite consensus, the scope of the Version 0 standards will incorporate the existing reliability rules in effect in April 2004 – namely the existing Board-approved operating policies and planning standards, the 38 compliance templates approved by the Board on April 2, and approved revisions to Operating Policies 5, 6, and 9 that are being balloted in April 2004. The Standards Authorization Committee (SAC) and the Standards Transition Management Team (STMT) strongly urge that previous transitional processes not be used to

further modify the existing operating policies, planning standards, and compliance templates during the translation to Version 0 standards.

2. In the drafting of Version 0 standards, when differences are identified in the language used in an existing operating policy or planning standard compared to that of a corresponding Board-approved compliance template, the more explicit statements of requirements and measures, generally contained in the compliance templates, will be adopted. For existing operating policy requirements that have no corresponding compliance template, the measures will be shown as “Not Specified”, rather than proposing new measures. Board-approved compliance templates for which there is no corresponding operating policy requirement or planning standard shall nonetheless be included as part of the Version 0 standards.
3. NERC will utilize the existing ANSI-accredited standards process for the development and adoption of the Version 0 standards. To expedite the transition, the Standards Authorization Committee (SAC) will manage some steps in parallel and manage the number of comment periods.
4. The Version 0 standards will be developed with due consideration of the impacts on existing NERC and Regional Council compliance monitoring programs.
5. NERC will work closely with NAESB, the IRC, the Regional Councils and the industry to achieve the stated objectives.
6. To facilitate consensus, a detailed mapping will be provided to show how the existing reliability documents translate into Version 0 standards, reference documents, and business practices. Therefore, each interim draft will retain information on the changes made, such as designation of new functions or identification of reference material or business practices.
7. A successful project depends on building consensus. Several checkpoints have been included in the project timeline to assess consensus.
8. All stakeholders are strongly encouraged to provide inputs early in the transition, especially during the public comment periods for the SAR and draft Version 0 standards. Because of the complexity of the project, no additional revisions will be permitted once the Version 0 standards are posted for committee and ballot pool approval.

Project Management

The NERC Director of Standards will serve as project director.

The STMT, comprised of the Vice Chairperson of each of the NERC committees, serves as the project requestor by sponsoring the SAR for the Version 0 standards and has associated decision authorities as outlined in the detailed schedule below. The STMT also ensures that the standards transition activities of the various committees are coordinated. Each committee retains its existing authorities and responsibilities as related to this project.

The SAC manages the ANSI-accredited standards development process for the development and approval of the Version 0 standards. Specific responsibilities are outlined in the detailed project schedule. Additionally, the SAC retains all of its responsibilities and authorities identified in the Standards Process Manual. The STMT and SAC must work closely together, with the SAC managing the standards process and the STMT coordinating work efforts and actions among the various committees.

In accordance with the Standards Process Manual, the SAC will appoint a Version 0 drafting team with due consideration of expertise and balance. To expedite the work effort, it is expected the drafting team may form subgroups, such as operating and planning, to work on portions of the Version 0 standards. A small support team, comprised of several staff members and consultants, will be assigned to assist the drafting team in developing their work.

Major Milestone Deliverables

The major milestone deliverables are as follows:

Date	Milestone
4/19/04	Transition plan approved for publication.
4/19/04	SAR on Version 0 standards posted for comment until May 17.
4/19/04	Solicit nominations for Version 0 drafting team and self-selection for ballot pool.
5/7/04	Version 0 drafting team formed.
5/28/04	Consideration of comments on the SAR posted. Evaluation of consensus based on comments received and support for project.
6/4/04	Inputs to Version 0 standards received from technical subcommittees.
7/2/04	First draft of Version 0 standards posted for standing committee agendas and public comment.
8/30/04	Second draft Version 0 standards posted for public comment until October 15, 2004
10/15/04	Initial registration of applicable reliability functions completed.
10/25/04	Third draft Version 0 standards posted to standing committees for endorsement at November 8-12 meetings.
10/25/04	Third draft Version 0 standards posted to ballot pool for 30-day pre-ballot period.
11/12/04	Standing committees endorse Version 0 standards.
12/10/04	Initial ballot of Version 0 standards complete.
1/7/05	Second ballot of Version 0 standards complete (assuming a recirculation ballot is required).
1/10/05	Final draft Version 0 standards posted for Board adoption.
2/8/05	Board adoption of Version 0 standards.

Implementation Schedule

The schedule below provides a work plan to achieve the stated objectives. The dates shown are expected completion dates – many tasks must begin well before the specified dates.

Date	Task	Assigned To
4/14/04	Approve SAR for Version 0 standards and appoint STMT as SAR drafting team for the purpose of considering comments.	SAC
4/14/04	Approve Version 0 standard drafting team nomination form.	SAC
4/19/04	Approve transition plan.	STMT/SAC
4/19/04	Post and announce: • Transition plan. • SAR (through 5/17/04). • Request for nominations to Version 0 standard drafting team (through 4/30/04). • Self-selection for Version 0 ballot pool.	NERC Staff
4/19/04	Assign technical subcommittees to provide inputs to Version 0 standards, as appropriate.	OC/PC/MC
4/19/04	Assign 3-4 person dedicated Support Team (ST), comprised of staff and contractors, to begin initial work and assist drafting team.	NERC Staff
4/19/04	Inform MC and NAESB of need to form a business practice review team (BPRT) to coordinate assimilation of business practices.	NERC Staff
4/19/04	Inform Organization Certification Working Group and Regional Councils of objectives and timeline for initial functional registration by October 15, 2004.	NERC Staff
4/19/04	Inform CCC and CCMC of objectives and timeline for evaluating impacts on the 2005 compliance program and preparing the 2005 compliance plan.	NERC Staff
4/21-22/04	OC subcommittees meet and work on inputs to Version 0	OC
4/30/04	Close nominations for Version 0 standard drafting team.	NERC Staff
4/30/04	Approve posting of Standards Process Manual (SPM) revision to allow SAC to make administrative and procedural revisions to the manual.	SAC
5/7/04	Approve Version 0 standard drafting team.	SAC
5/14/04	Initial mapping of compliance templates into Version 0 format. Significant progress in mapping planning standards into Version 0 format.	ST

5/17/04	Close Version 0 SAR comment period.	NERC Staff
5/17/04	Post revision to SPM for comment through June 17.	SPM DT
5/18/04	Review SAR and project plans with JIC for informational purposes.	SAC/JIC
5/20-21/04	Initial meeting of Version 0 drafting team (DT).	DT/ST
5/28/04	Prepare and post consideration of comments on SAR. Evaluate and report to SAC on consensus.	STMT
5/28/04	Finalize Version 0 communications plan.	SAC
5/28/04	Assess consensus based on SAR comments and approve drafting of Version 0 standards.	SAC
6/4/04	Provide inputs to draft Version 0 standards.	OC/PC/MC
6/4/04	Forward OC/PC/MC subcommittee recommendations on business practices to BPRT.	NERC Staff
6/9-11/04	Version 0 drafting team second meeting.	DT/ST
6/9/04	Version 0 drafting team finalizes general organization and numbering scheme for Version 0 standards.	DT/ST
6/15/04	Approve transition project.	Board
6/28-30	Drafting team third meeting to finalize draft 1 of Version 0 standards.	DT/ST
7/2/04	Post first draft of Version 0 standards for standing committee agendas and public comment. Key unresolved issues highlighted.	NERC Staff
7/20-26	Standing committee review of first draft Version 0.	OC/PC/MC/CIPC
7/30/04	Close comment period on first draft of Version 0 standard.	NERC Staff
8/9-10/04	SAC meeting.	SAC
8/11-13/04	Drafting team meeting to prepare second draft and response to comments.	DT/ST
8/30/04	Post second draft Version 0 standards for public comment until 10/15/04.	DT/ST
8/30/04	Complete ballot of revision to SPM to allow SAC revisions to administrative procedures.	SPM DT
10/4/04	Proposed revisions to streamline SPM steps posted for 30-day comment period.	
10/15/04	Complete initial registration of applicable reliability functions.	OCTF/Reliability Councils
10/15/04	Close comment period on draft 2.	NERC Staff
10/22/04	Prepare consideration of comments on draft 2 and prepare draft 3 of Version 0 for posting to standing committees for	DT/ST

	endorsement at November 9-11 meetings.	
10/25/04	Evaluate consensus and determine whether to ballot Version 0 standards.	SAC
10/25/04	Post draft 3 Version 0 standards to ballot pool for 30-day pre-ballot period.	NERC Staff
11/8-12/04	Standing committees endorse Version 0 standards by committee action.	OC/PC/MC/CIPC
11/11-12/04	SAC meeting. Assess consensus on Version 0 going to ballot and proposed revisions to streamline the Standards Process Manual.	SAC
12/10/04	Complete first ballot of Version 0 standards.	Ballot Pool
12/15/04	Complete consideration of comments submitted with negative ballots, if needed.	SPM/Drafting Team
1/7/05	Complete recirculation ballot of Version 0 standards, if needed.	Ballot Pool
1/10/05	Post final draft Version 0 standards for Board adoption February 8, 2005	NERC Staff
1/12/05	SCEC and SAC executives joint meeting to coordinate use of technical resources in development of standards.	SCEC/SAC
2/8/05	Board considers adoption of Version 0 standards.	BOT

NERC Reliability Standards
Accelerated Transition to Version 0

Gerry Cauley
Director – Standards
April 21, 2004

Accelerated Standards Transition

- Message from August 14: need for clear and measurable standards:
  - US/Canada TF Report Recommendation 25
  - FERC Reliability Policy Order
- Multiple sets of 'reliability rules' and processes
  - Operating policies, planning standards, compliance templates, new standards
  - Industry volunteer resources spread too thin
- Consensus on new standards takes time
- Need to minimize cost and impacts of standards transition
- Need to ensure reliability continuity

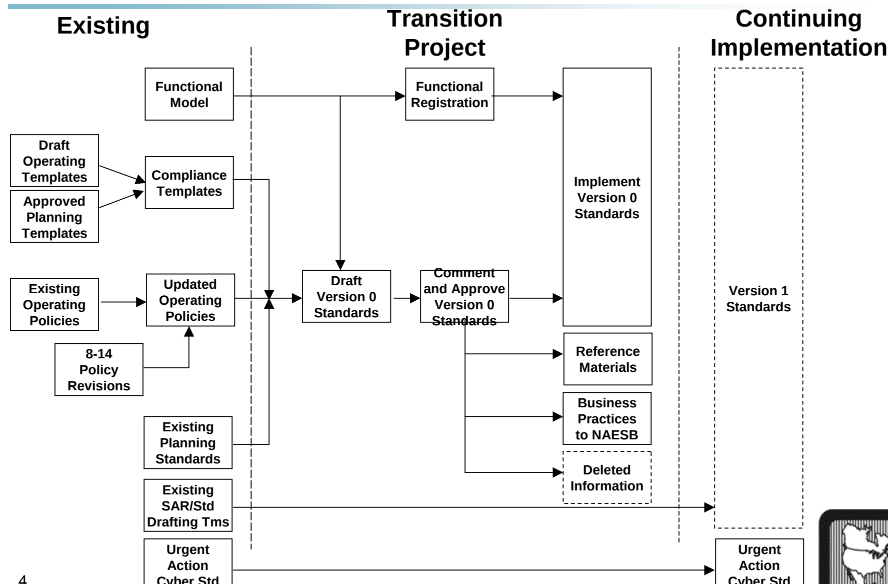
NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Objectives by 2/05

- Translate existing operating policies, planning standards, and compliance templates into 'Version 0' reliability standards
  - Identify functions
  - Split out business practice sections to NAESB
  - Minimal 'content' change
  - Use ANSI-accredited process
- Complete initial function registrations
- Adopt 'Version 0' standards and retire existing policies, standards, templates
- Consolidate resources for standards development
- Streamline standards process

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Project Overview



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Transition Steps

- Board approved compliance templates 4-2
- Revisions to Policies 5, 6, and 9 balloted
- Staff and consultant support available
- Drafting team nominations due 4/30
- SAR/Plan posted until May 19 (STMT)
- Committee inputs due 6/4
- Drafting team draft Version 0 due 7/2
- Committee meetings to review/key issues
- Post draft 2 August 30 to October 15
- Initial functional registration due October 31
- Committee approval Version 0 in November
- RBB ballot on Version 0 in December
- BOT adoption in February 2005

Version 0 Format Guidelines

- Template
  - Title
  - Purpose
  - Requirements
  - Measures
  - Regional Differences
  - Compliance Monitoring
- Control Area (FM Function)
- Identify potential
  - Business practices
  - References
  - Deletions
- Guides are not requirements
- Do not change scope of reliability rules

Benefits of Accelerated Transition

- Address FERC reliability initiative for enforceable standards
- Focus work on one set of reliability rules
- Use one, ANSI-accredited process
- Minimize initial impact of transition to new standards by removing “step jump”
- Reduce burden on industry to follow multiple groups
- Facilitate NAESB adoption of business practices
- Streamline standards development process going forward

Existing	Compliance Template	Proposed Reliability SAR
Operating Policies		
Policy 1 — Generation Control and Performance		
A. Control Performance Standard	P1T1	300 - Balance Resources and Demand
B. Disturbance Control Standard	P1T2, P1T4	
C. Frequency Response Standard		300 - Balance Resources and Demand
D. Time Control Standard		
E. Automatic Generation Control Standard	P1T4	
F. Inadvertent Interchange Standard		
G. Surveys Standard		
Policy 2 — Transmission		
A. Transmission Operations	P2T1, P2T2	200 - Operate Within Interconnection Reliability Operating Limits
B. Voltage and Reactive Control	P2T1, P2T2	200 - Operate Within Interconnection Reliability Operating Limits
Policy 3 — Interchange (Revised10/03)		
A. Interchange Transaction Implementation	P3T3	400 - Coordinate Interchange
B. Interchange Schedule Implementation	P3T3	400 - Coordinate Interchange
C. Interchange Schedule Standards	P3T3	400 - Coordinate Interchange
D. Interchange Transaction Modifications	P3T3	
Policy 4 — System Coordination		
A. Monitoring System Conditions		200 - Operate Within Interconnection Reliability Operating Limits
B. Operational Security Information	P4T2	100 - Coordinate Operations
C. Maintenance Coordination	P4T4	100 - Coordinate Operations
D. System Protection Coordination		800 - Design, Install, and Coordinate Control and Protection Systems
Policy 5 — Emergency Operations (Under Revision)		
A. Coordination with Other Systems		1000 - Prepare for and Respond to Abnormal or Emergency Conditions 1100 - Prepare for and Respond to Blackout or Island Conditions
B. Insufficient Generating Capacity	P5T1	1000 - Prepare for and Respond to Abnormal or Emergency Conditions
C. Transmission System Relief	P5T1	1000 - Prepare for and Respond to Abnormal or Emergency Conditions
D. Separation from the Interconnection		1000 - Prepare for and Respond to Abnormal or Emergency Conditions 1100 - Prepare for and Respond to Blackout or Island Conditions
E. System Restoration		1000 - Prepare for and Respond to Abnormal or Emergency Conditions 1100 - Prepare for and Respond to Blackout or Island Conditions

Existing	Compliance Template	Proposed Reliability SAR
F. Disturbance Reporting		900 - Monitor and Analyze Disturbances, Events and Conditions
G. Sabotage Reporting		
Policy 6 — Operations Planning (Under Revision)		
A. Normal Operations		100 - Coordinate Operations
B. Emergency Operations	P6T1	1000 - Prepare for and Respond to Abnormal or Emergency Conditions
C. Automatic Load Shedding		1000 - Prepare for and Respond to Abnormal or Emergency Conditions
D. System Restoration	P6T2	1000 - Prepare for and Respond to Abnormal or Emergency Conditions 1100 - Prepare for and Respond to Blackout or Island Conditions
E. Control Center Backup	P6T3	1000 - Prepare for and Respond to Abnormal or Emergency Conditions
Policy 7 — Telecommunications		
A. Facilities		1200 - Cyber Security (Urgent Action) 1300 – Cyber Security (Permanent)
B. System Operator Telecommunication Procedures		1000 - Prepare for and Respond to Abnormal or Emergency Conditions
C. Loss of Telecommunications		1000 - Prepare for and Respond to Abnormal or Emergency Conditions
D. Security		1200 - Cyber Security (Urgent Action) 1300 – Cyber Security (Permanent)
Policy 8 — Operating Personnel and Training		
A. Responsibility and Authority	P8T1	1400 - Certification of the Balancing Authority Function 1500 - Certification of the Interchange Authority Function 1600 - Certification of the Reliability Authority Function
B. Training		
C. Certification	P8T2	1400 - Certification of the Balancing Authority Function 1500 - Certification of the Interchange Authority Function 1600 - Certification of the Reliability Authority Function
Policy 9 — Reliability Coordinator Procedures (Under Revision)		
A. Next Day Operations Planning Process	P9T1, P9T4	100 - Coordinate Operations 200 - Operate Within Interconnection Reliability Operating Limits
B. Current Day Operations - Energy	P9T4	100 - Coordinate Operations 200 - Operate Within Interconnection Reliability Operating Limits 300 - Balance Resources and Demand
C. Current Day Operations - Transmission	P9T2, P9T3, P9T4	100 - Coordinate Operations 200 - Operate Within Interconnection Reliability Operating Limits
Existing		**Proposed Reliability SAR**

Existing	Compliance Template	Proposed Reliability SAR
Planning Standards		
I. System Adequacy and Security		
A. Transmission Systems	I.A	500 - Assess Transmission Future Needs and Develop Transmission Plans
B. Reliability Assessment	I.B	500 - Assess Transmission Future Needs and Develop Transmission Plans
C. Facility Connection Requirements		700 - Define (Physical) Connection Requirements
D. Voltage Support and Reactive Power		500 - Assess Transmission Future Needs and Develop Transmission Plans
E. Transfer Capability		600 - Determine Facility Ratings, Operating Limits, and Transfer Capabilities
F. Disturbance Monitoring	I.F	900 - Monitor and Analyze Disturbances, Events and Conditions
II. System Modeling Data Requirements		
A. System Data	II.A	500 - Assess Transmission Future Needs and Develop Transmission Plans
B. Generation Equipment		
C. Facility Ratings	II.C	600 - Determine Facility Ratings, Operating Limits, and Transfer Capabilities
D. Actual and Forecast Demands		500 - Assess Transmission Future Needs and Develop Transmission Plans
E. Demand Characteristics (Dynamic)		
III. System Protection and Control		
A. Transmission Protection Systems	III.A	800 - Design, Install, and Coordinate Control and Protection Systems
B. Transmission Control Devices		800 - Design, Install, and Coordinate Control and Protection Systems
C. Generation Control and Protection		800 - Design, Install, and Coordinate Control and Protection Systems
D. Under Frequency Load Shedding	III.D	800 - Design, Install, and Coordinate Control and Protection Systems
E. Under Voltage Load Shedding	III.E	800 - Design, Install, and Coordinate Control and Protection Systems
F. Special Protection Systems	III.F	800 - Design, Install, and Coordinate Control and Protection Systems
IV. System Restoration		
A. System Blackstart Capability	IV.A	1100 - Prepare for and Respond to Blackout or Island Conditions
B. Automatic Restoration of Load		1100 - Prepare for and Respond to Blackout or Island Conditions

Version 0 Standards – Development and Tracking Template			
Draft Version 0 Standard		Source ID	Source Information
ID Number			
Title			
Purpose			
Effective Date			
Applicability			
Requirements			
Measures			
Regional Differences			
Compliance Monitoring Process			

Reliability Principle 2	The frequency and voltage of interconnected BULK ELECTRIC SYSTEMS shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
Brief Description	Control Performance Standard, Load and Generation Matching, and Frequency Control
Section	Policy 1, Section A, Control Performance Standard
Standard	CPS 1 and CPS 2 Control Performance Standards

Applicable to

CONTROL AREAS

Monitoring Responsibility

Regional Reliability Council (RRC)

Measuring Processes

Compliance with the CPS 1 standard shall be measured on a percentage basis as set forth in the NERC Performance Standard Training Document.

Periodic Review
CONTROL AREAS must have achieved the minimum compliance level and must send one completed copy of the CPS 1 and CPS 2 form "NERC Control Performance Standard Survey-All Interconnections" each month to the Regions as per established dates.

The Regional Reliability Council must submit a summary document reporting compliance with CPS 1 and CPS 2 to NERC no later than the 20th day of the following month.

Periodic Compliance Monitoring
Compliance for CPS 1 and CPS 2 will be evaluated for each reporting period.

Reporting Period

One calendar month

100% Compliance

The CONTROL AREA meets the CPS 1 and CPS 2 Control Performance Standards, when CPS 1 is greater than or equal to 100% and CPS 2 is greater than or equal to 90% in a reporting period.

Levels of Non-Compliance

Non-compliance for CPS 1 and CPS 2 is evaluated separately. Non-compliance for CPS 1 in a month, shall mean that the rolling twelve month average of CPS 1 ending in that month is less than 100%. Non-compliance for CPS 2 shall mean that the monthly CPS 2 average is below 90%. Both CPS 1 and CPS 2 are calculated and evaluated monthly.

CPS 1

Level 1 — The CONTROL AREA'S value of CPS 1 is less than 100% but greater than or equal to 95%.

Level 2 — The CONTROL AREA'S value of CPS 1 is less than 95% but greater than or equal to 90%.

Level 3 — The CONTROL AREA'S value of CPS 1 is less than 90% but greater than or equal to 85%.

Level 4 — The CONTROL AREA'S value of CPS 1 is less than 85%.

CPS2

Level 1 — The CONTROL AREA'S value of CPS 2 is less than 90% but greater than or equal to 85%.

Level 2 — The CONTROL AREA'S value of CPS 2 is less than 85% but greater than or equal to 80%.

Level 3 — The CONTROL AREA'S value of CPS 2 is less than 80% but greater than or equal to 75%.

Level 4 — The CONTROL AREA'S value of CPS 2 is less than 75%.

Compliance Assessment Notes

Verification of compliance will be done through established periodic monitoring processes.

Compliance Reset Period

One calendar month without a violation.

Data Retention Period

The data that supports the calculation of CPS 1 and CPS 2 are to be retained in electronic form for at least a one-year period. If the CPS 1 and CPS 2 data for a CONTROL AREA are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

CPS 1 DATA	Description	Retention Requirements
ε1	A constant derived from the targeted frequency bound. This number is the same for each CONTROL AREA in the INTERCONNECTION.	Retain the value of ε1 used in CPS 1 calculation.
ACEi	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
βi	The frequency bias of the CONTROL AREA.	Retain the value(s) of Bi used in the CPS 1 calculation.
FA	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
Fs	Scheduled frequency for the INTERCONNECTION.	Retain the 1-minute average frequency values (525,600 values).

CPS 2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE is greater than L10.	Retain the values of V used in CPS 2 calculation.
ε10	A constant derived from the frequency bound. It is the same for each CONTROL AREA within an INTERCONNECTION.	Retain the value of ε10 used in CPS 2 calculation.
βi	The frequency bias of the CONTROL AREA.	Retain the value of Bi used in the CPS 2 calculation.
βs	The sum of frequency bias of the CONTROL AREAS in the respective INTERCONNECTION. For systems with variable bias, this is equal to the sum of the minimum frequency bias setting.	Retain the value of Bs used in the CPS 2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS 2.	Retain the number of 10-minute unavailable periods used in calculating CPS 2 for the reporting period.

Reliability Principle 2	The frequency and voltage of INTERCONNECTED BULK ELECTRIC SYSTEMS shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
Brief Description	Disturbance Control Standard
Section	Policy 1, Section B, Disturbance Control Standard
Standard	ACE must be returned to zero or to its pre-disturbance level within the DISTURBANCE RECOVERY PERIOD following the start of a Reportable Disturbance.

Applicable to

CONTROL AREAS that are not part of a RESERVE SHARING GROUP, and RESERVE SHARING GROUPS.

Monitoring Responsibility

Regional Reliability Councils (RRC's)

Measuring Processes

Compliance with the Disturbance Control Standard (DCS) shall be measured on a percentage basis as set forth in the NERC Performance Standard Training Document.

Periodic Review
CONTROL AREAS and/or RESERVE SHARING GROUPS must return one completed copy of DCS form "NERC Control Performance Standard Survey-All Interconnections" each quarter to the Region as per set dates.

The Regional Reliability Council must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

Periodic Compliance Monitoring
Compliance for DCS will be evaluated for each reporting period.

Reporting Period

One calendar quarter

100% Compliance

CONTROL AREA or RESERVE SHARING GROUP returned the ACE to zero or to its pre-disturbance level within the DISTURBANCE RECOVERY PERIOD, following the start of all Reportable Disturbances. DCS is calculated quarterly and compliance evaluated as the Average Percentage Recovery (APR) as defined in the Performance Standard Training Document.

Levels of Non-Compliance

Level 1— Value of APR is less than 100% but greater than or equal to 95%.

Level 2 — Value of APR is less than 95% but greater than or equal to 90%.

Level 3 — Value of APR is less than 90% but greater than or equal to 85%.

Level 4 — Value of APR is less than 85%.

Compliance Assessment Notes

Verification of compliance will be done through established periodic monitoring processes.

Compliance Reset Period

One calendar quarter without a violation.

Data Retention Period

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a RESERVE SHARING GROUP and CONTROL AREA are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

DCS DATA	Description	Retention Requirements
MW loss	The MW size of the disturbance as measured at the beginning of the loss.	Retain the value of MW loss used in DCS calculation.
ACEA	The pre-disturbance ACE.	Retain the value of ACEA used in DCS calculation.
ACEM	The maximum algebraic value of ACE measured within ten minutes following the disturbance event.	Retain the value of ACEM used in the DCS calculation.
ACE_m	The minimum algebraic value of ACE measured within the recovery period following the disturbance event.	Retain the value of ACE_m used in the DCS calculation.
Date of incident	The date the incident occurred.	Retain the date.
Time of incident	The time of the incident in hours, minutes, and seconds.	Retain the time as precise as possible.
Description of incident	Describe the incident in sufficient details to define the incident.	Retain sufficient details to define the incident, i.e. name and MW output of unit that tripped. Cause of incident.
Recovery Time Duration	The duration of time of the incident in hours, minutes, and seconds to have the ACE return to 0.	Retain the incident time as precise as possible.

Reliability Principle 1 INTERCONNECTED BULK ELECTRIC SYSTEMS shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Brief Description System Operating Limit Reporting and INTERCONNECTED RELIABILITY OPERATING LIMIT (IROL)Violations

Section Policy 2, Section A, Standard 2
Policy 9, Section E

Standard

The CONTROL AREA Operator or Transmission Operator shall inform the RELIABILITY COORDINATOR of SOL or IROL violations, the actions they are taking to return the system to within limits, and shall implement directives of the RELIABILITY COORDINATOR.

When an IROL (as defined below) is exceeded, the CONTROL AREA Operator or Transmission Operator shall take corrective actions to return the system to within the IROL within 30 minutes.

Applicable to

CONTROL AREA Operators or Transmission Operators

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

The CONTROL AREA Operator or Transmission Operator has informed the RELIABILITY COORDINATOR when an IROL or SOL has been exceeded and the actions they are taking to return the system to within limits.

For each incident that an IROL, or SOL that has become an IROL due to changed system conditions, is exceeded, the CONTROL AREA or Transmission Operator returned the system to within IROL within 30 minutes.

Compliance Assessment Notes
The RELIABILITY COORDINATOR provides to the CONTROL AREA Operator or Transmission Operator the list of known IROL(s) and notification of any System Operating Limits that have become IROLs because of changed system conditions i.e. exceeding the limit will require actions to prevent:

1) System instability;
2) Unacceptable system dynamic response or equipment tripping;
3) Voltage levels in violation of applicable emergency limits;
4) Loadings on transmission facilities in violation of applicable emergency limits;
5) Unacceptable loss of load based on regional and/or NERC criteria.

System Operating Limit (SOL): The value (such as MW, MVar, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-CONTINGENCY equipment or facility ratings)
- Transient Stability Limits (Applicable pre- and post-CONTINGENCY Stability Limits)
- Voltage Stability Limits (Applicable pre- and post-CONTINGENCY Voltage Stability)
- System Voltage Limits (Applicable pre- and post-CONTINGENCY Voltage Limits)

Interconnected Reliability Operating Limit (IROL): The value established by the RELIABILITY COORDINATOR (such as MW, MVar, Amperes, Frequency, or Volts) derived from, or a subset of, the SYSTEM OPERATING LIMITS, which if exceeded, could expose a widespread area of the BULK ELECTRICAL SYSTEM to instability, uncontrolled separation(s) or cascading outages.

Measuring Processes

Incident Reporting
The CONTROL AREA Operators and Transmission Operators shall report to its RELIABILITY COORDINATOR all occurrences in which an INTERCONNECTED RELIABILITY OPERATING LIMIT or System Operating Limit is exceeded.

The RELIABILITY COORDINATOR will report any IROL and/or SOL violations (for which actions are required for items 1 through 5) exceeding 30 minutes to the RRC.

Each RRC shall report violations of the 30-minute rule to NERC via the NERC Compliance Reporting process.

100% Compliance

The CONTROL AREA Operator or Transmission Operator returned the system to within the IROL within 30 minutes.

Levels of Non-Compliance

The CONTROL AREA Operator or Transmission Operator did not inform the RELIABILITY COORDINATOR of an IROL or SOL (for which actions are required for items 1 through 5) violation and the actions they are taking to return the system to within limits, or

The CONTROL AREA Operator or Transmission Operator did not take corrective actions as directed by the RELIABILITY COORDINATOR to return the system to within the IROL within 30 minutes.

Percentage by which IROL or SOL that has become an IROL is exceeded	Limit exceeded for more than 30 minutes, up to 35 minutes.	Limit exceeded for more than 35 minutes, up to 40 minutes.	Limit exceeded for more than 40 minutes, up to 45 minutes.	Limit exceeded for more than 45 minutes.
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes)

Compliance Reset Period

Monthly

Data Retention Period

Three months

Monitoring Period

Monthly

Reliability Principle 1 INTERCONNECTED BULK ELECTRIC SYSTEMS shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Brief Description System Operating and INTERCONNECTED RELIABILITY OPERATING LIMIT Violations

Section Policy 2, Section A, Standard 2
Policy 9, Section E

Standard

When an IROL or SOL is exceeded, the RELIABILITY COORDINATOR shall evaluate the impact both real-time and post-contingency on the Wide Area system 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 provide direction to the CONTROL AREA Operator or Transmission Operator to return the system to within limits.

Applicable to

RELIABILITY COORDINATORS

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

Verify that the RELIABILITY COORDINATOR evaluated actions and provided direction as required to the CONTROL AREA Operator or Transmission Operator to return the system to within limits.

Compliance Assessment Notes
The CONTROL AREA Operator or Transmission Operator shall inform the RELIABILITY COORDINATOR when an SOL has been exceeded.

System Operating Limit (SOL): The value (such as MW, MVar, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-CONTINGENCY equipment or facility ratings)
- Transient Stability Limits (Applicable pre- and post-CONTINGENCY Stability Limits)
- Voltage Stability Limits (Applicable pre- and post-CONTINGENCY Voltage Stability)
- System Voltage Limits (Applicable pre- and post-CONTINGENCY Voltage Limits)

Interconnected Reliability Operating Limit (IROL): The value established by the RELIABILITY COORDINATOR (such as MW, MVar, Amperes, Frequency, or Volts) derived from, or a subset of, the SYSTEM OPERATING LIMITS, which if exceeded, could expose a widespread area of the BULK ELECTRICAL SYSTEM to instability, uncontrolled separation(s) or cascading outages. These may be established in advance by the RELIABILITY COORDINATOR based on system studies or identified based on an analysis of system conditions as they exist or existed.

Measuring Processes

Exception Reporting
RELIABILITY COORDINATORS shall report to its Regional Reliability Council any occurrences where an IROL violation extended beyond 30 minutes. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

100% Compliance

The RELIABILITY COORDINATOR evaluated the impact both real-time and post-contingency on the Wide Area system of the IROL, and where required, provided direction to the CONTROL AREA Operator or Transmission Operator to return the system to within limits within 30 minutes.

Levels of Non-Compliance

The limit violation was reported to the RELIABILITY COORDINATOR who did not provide appropriate direction to the CONTROL AREA Operator or Transmission Operator resulting in an IROL violation in excess of 30 minutes duration.

Percentage by which IROL is exceeded	**Limit exceeded for more than 30 minutes, up to 35 minutes.**	**Limit exceeded for more than 35 minutes, up to 40 minutes.**	**Limit exceeded for more than 40 minutes, up to 45 minutes.**	**Limit exceeded for more than 45 minutes.**
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes)

Compliance Reset Period

Monthly

Data Retention Period

Three months

Monitoring Period

Monthly

Reliability Principle 3 Information necessary for planning and operating interconnected BULK ELECTRIC SYSTEMS shall be made available to those entities responsible for planning and operating the systems reliably.

Brief Description Interchange Transaction Implementation and Electronic Tagging

Standard

All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged as required by each Interconnection. In addition, intra-CONTROL AREA transfers using Point-to-Point Transmission Service[1] shall be tagged. This includes:

- INTERCHANGE TRANSACTIONS (those that are between CONTROL AREAS).
- TRANSACTIONS that are entirely within a CONTROL AREA.
- DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile according to Compliance Template P3T4)
- INTERCHANGE TRANSACTIONS for bilateral INADVERTENT INTERCHANGE payback (tagged by the SINK CONTROL AREA).

INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins (tagged by the SINK CONTROL AREA).

Applicable to

Control Areas

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

Every CONTROL AREA must meet the 100% tagging requirements for all scheduled interchange between CONTROL AREAS as required by the standard.

Measuring Process

Periodic tag audits as prescribed by NERC. The CONTROL AREA shall demonstrate as required by NERC that all Scheduled Interchange has one or more approved and confirmed E-Tag(s) associated with each transaction for the requested audit period.

Levels of Non-Compliance

Level 1 — N/A

Level 2 — N/A

Level 3 — N/A

Level 4 — One or more energy schedules implemented as Scheduled Interchange were not tagged as required in the standard above.

[1] This includes all "grandfathered" and other "non-888" Point-to-Point Transmission Service

Compliance Reset Period

One calendar year without a violation from the time of the violation

Data retention requirements

Three months

Occurrence Period

One calendar year

Principle 3 Information necessary for planning and operating interconnected BULK ELECTRIC SYSTEMS shall be made available to those entities responsible for planning and operating the systems reliably.

Brief Description Interchange Transaction Implementation — Required E-Tag revisions for a DYNAMIC INTERCHANGE SCHEDULE

Standard

DYNAMIC INTERCHANGE SCHEDULES shall be tagged at the expected average MW profile for each hour. A change in the hourly energy profile of 25% or more requires a revised tag.

The SINK CONTROL AREA for a DYNAMIC INTERCHANGE SCHEDULE shall ensure that a revised E-Tag is provided whenever the projected energy transfer of the DYNAMIC INTERCHANGE SCHEDULE changes by 25% or more from the expected average MW profile for each hour provided in the E-Tag.

Applicable to

SINK CONTROL AREA operating to one or more DYNAMIC INTERCHANGE SCHEDULES

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

The SINK CONTROL AREA will demonstrate as required by NERC that a revised E-Tag was submitted when the variance between the expected average MW profile for each hour provided in the E-Tag, and the actual DYNAMIC INTERCHANGE SCHEDULE integrated over each hour, was 25% or more for two consecutive hours.

Measuring Processes

Periodic tag audit as prescribed by NERC.

For the requested time period, the SINK CONTROL AREA will provide the instances when the variance between the expected average MW profile for each hour provided in the E-Tag, and the actual DYNAMIC INTERCHANGE SCHEDULE integrated over each hour, was 25% or more for two consecutive hours. For each instance identified, the CONTROL AREA shall demonstrate that a revised E-Tag was submitted.

Levels of Non-Compliance

Level 1 — One tag was not updated according to the requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Level 2 — Two tags were not updated according to the requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Level 3 — Three tags were not updated according to the requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Level 4 — Four or more tags are not updated according to the requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Compliance Reset Period

One calendar year without a violation from the time of the violation

Data retention requirements

Three months

Occurrence Period

One Calendar year

Reliability Principle Information necessary for planning and operating interconnected BULK ELECTRIC SYSTEMS shall be made to those entities responsible for planning and operating the systems reliably.

Brief Description System Coordination/Operational Security Information

Section Policy 4, Section B Requirements 3, 3.1

Standard

Each CONTROL AREA or other OPERATING AUTHORITY shall provide its RELIABILITY COORDINATOR (RC) with operating data that the RELIABILITY COORDINATOR requires to monitor system conditions within the RELIABILITY COORDINATOR AREA. The RC will identify the data requirements from the list in Policy 4, Appendix 4B. The RC will identify any additional operating information requirements, relating to operation of the bulk power system and also, which data must be provided electronically.

Applicable to

CONTROL AREAS and other Entities Responsible for the Reliability of the Interconnected System (ERRIS).

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

The CONTROL AREA or OPERATING AUTHORITY meets 100% compliance when they provide the RELIABILITY COORDINATOR with the information required, within the time intervals specified therein, and in a format agreed upon by the RELIABILITY COORDINATOR.

Compliance Assessment Notes

Each RELIABILITY COORDINATOR will prepare a list of data requirements, formats, and time intervals for reporting.

Measuring Processes

Periodic Review

The CONTROL AREA or OPERATING AUTHORITY will be selected for operational reviews at least every three years

Self-Certification

Each CONTROL AREA or other ERRIS shall annually self-certify compliance to the measures as required by its RRC.

Levels of Non-Compliance

Level 1 — The CONTROL AREA or OPERATING AUTHORITY is providing the RELIABILITY COORDINATOR with the data required, in specified time intervals and format, but there are problems with consistency of delivery identified in the measuring process that need remedy (e.g., the data is not supplied consistently due to equipment malfunctions, or scaling is incorrect).

Level 2 — N/A

Level 3 — N/A

Level 4 — The CONTROL AREA or OPERATING AUTHORITY is not providing the RELIABILITY COORDINATOR with data having the specified content, or time interval reporting, or format. The information missing is included in the RC's list of data**.**

Compliance Reset Period

One year without a violation from the time of the violation.

Data Retention Period

N/A

Monitoring Period

One calendar year

Reliability Principle 1 Interconnected BULK ELECTRIC SYSTEMS shall be planned and operated and maintained in a coordinated manner to perform reliably under normal and abnormal conditions.

Reliability Principle 3 Information necessary for planning and operating interconnected BULK ELECTRIC SYSTEM shall be made available to those entities responsible for planning and operating the system reliably.

Section Policy 4, Section C, Requirement 1

Standard

Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among CONTROL AREAS and other ERRIS.

Applicable to

CONTROL AREAS and other ERRIS

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

The CONTROL AREA and other ERRIS must report and coordinate scheduled generator and/or bulk transmission outages to the directly interconnected CONTROL AREAS and to its RELIABILITY COORDINATOR. The RELIABILITY COORDINATORS will resolve any scheduling of potential reliability conflicts.

Compliance Assessment Notes
The operating records of the CONTROL AREA for a period of at least one month, (from a three month rolling window), shall be inspected in the field audit to verify that scheduled generator and transmission outages have been planned and coordinated among affected systems and control areas. These records are subject to correlation and confirmation with adjacent ERRIS.

Each neighboring CONTROL AREA shall develop and share a list of critical facilities that it will receive notification of future and actual outages.

Requirements

The CONTROL AREA must provide outage information daily, by noon, for scheduled generator and bulk transmission outages planned for the next day (any transmission line or transformer > 100 kV or generator outage >50 MW that is not a forced outage) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation, to their RELIABILITY COORDINATOR, and to neighboring CONTROL AREAS. The RC shall establish the outage reporting requirements.

Measuring Process

Periodic Review
The Regional Reliability Councils shall conduct a review every three years to ensure that each CONTROL AREA has a process in place to provide planned generator and/or bulk transmission outage information to their RELIABILITY COORDINATOR, and with neighboring CONTROL AREAS.

Investigation
At the discretion of the RRC or NERC, an investigation may be initiated to review the planned outage process of a CONTROL AREA or ERRIS due to a complaint of non-compliance by another CONTROL AREA or ERRIS. Notification of an investigation must be made by the RRC to the CONTROL AREA being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the RRC.

An RC makes a request for an outage to "not be taken" because of a reliability impact on the grid and the outage is still taken. The RC must provide all its documentation within 3 business days to the region.

Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

100% Compliance

The CONTROL AREA or ERRIS has a process in place to provide planned generator and bulk transmission outage information to their RELIABILITY COORDINATOR and to their adjacent neighboring CONTROL AREAS as defined in the requirements.

Levels of Non-Compliance

Level 1 — A CONTROL AREA or ERRIS has a process in place to provide information to their RELIABILITY COORDINATOR but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring CONTROL AREAS.

Level 2 — N/A

Level 3 — N/A

Level 4 — There is no process in place to exchange outage information, or a CONTROL AREA or ERRIS does not follow the directives of the RELIABILITY COORDINATOR to cancel or reschedule an outage.

Compliance Reset Period

One calendar year without a violation.

Data Retention Period

One calendar year

Monitoring Period

One calendar year

Reliability Principle 4 Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.

Brief Description Emergency Operations/Implementation of Capacity and Energy Emergency plans and coordination with other systems

Section Policy 5, Sections B and C (Draft 7 dated 3/11/2004 of the ORS-RCWG proposed revision.)
Emergency Operations/Coordination with other systems

Standard

1. The ERRIS must implement their Capacity and Energy Emergency plans, when required and as appropriate, to reduce risks to the interconnected system.
2. The ERRIS must communicate its current and future system conditions to neighboring ERRIS and their RELIABILITY COORDINATOR if they are experiencing an operating emergency.

Applicable to

Entities responsible for the reliability of the interconnected system (ERRIS)

Monitoring Responsibility

Regional Reliability Councils (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure 1

The ERRIS will be reviewed to determine if their Capacity and Energy Emergency Plans were appropriately followed. ("Appropriately", since for a particular situation, not all of the steps may be effective or required).

Measure 2

Evidence will be gathered to determine the level of communication between the ERRIS and other ERRIS. An assessment will be made by the investigator(s) as to whether the level and timing of communication of system conditions and actions taken to relieve emergency conditions was acceptable and in conformance with the Capacity and Energy Emergency Plans.

Compliance Assessment Notes
The Regional Reliability Council must complete the evaluation of levels of compliance within 30 days of the start of the investigation or within a time frame as required by Regional Reliability Council procedures.

A time frame of 30 days after the start of the investigation or within a time frame as required by RRC procedures has been established to ensure that an ERRIS will have closure to any investigation within a reasonable time.

Measuring Process

Investigation
At the discretion of the Regional Reliability Council or NERC, an investigation may be initiated to review the operation of an ERRIS when they have implemented their Capacity and Energy Emergency plans. Notification of an investigation must be made by the Regional Reliability Council to the ERRIS being investigated as soon as possible, but no later than 60 days after the event.

100% Compliance

The ERRIS implemented their Capacity and Energy Emergency plans, when required and as appropriate and communicated its system conditions to neighboring ERRIS and their RELIABILITY COORDINATOR as required.

Levels of Non-Compliance

Level 1 — N/A

Level 2 — N/A

Level 3 **—** One or more of the actions of the Capacity and Energy Emergency Plans were not implemented resulting in a prolonged abnormal system condition.

Level 4 **—** One or more of the actions of the Capacity and Energy Emergency Plans were not implemented resulting in a prolonged abnormal system condition and there was a delay or gap in communications.

Compliance Reset Period

One year without a violation from the time of the violation

Data Retention Period

The ERRIS is required to maintain operational data, logs and voice recordings relevant to the implementation of the Capacity and Energy Emergency Plans for 60 days following the implementation.

After an investigation is completed, the Regional Reliability Council is required to keep the report of the investigation on file for two years.

Monitoring Period

One calendar year.

Reporting Period

Each event

Reliability Principle 4 Plans for emergency operation and system restoration of interconnected BULK ELECTRIC SYSTEMS shall be developed, coordinated, maintained and implemented.

Brief Description Emergency Operations/Preparation of Capacity and Energy Emergency Plans

Section Policy 6, Section B, Requirements 3 and 4

Standard

Capacity and Energy Emergency plans consistent with NERC Operating Policies shall be developed and maintained by each CONTROL AREA and OPERATING AUTHORITY to cope with operating emergencies.

Applicable to

CONTROL AREAS and OPERATING AUTHORITIES

Monitoring Responsibility

Regional Reliability Councils (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

CONTROL AREA and OPERATING AUTHORITY emergency plans must address the essential "Functional Areas of a Capacity and Energy Emergency Plan" listed below.

Compliance Assessment Notes

The Capacity and Energy Emergency Plan must address the following requirements:

(Some of the items may not be applicable, as the responsibilities for the item may not rest with the entity being reviewed, and therefore, they should not be penalized for not having that item in the plan.)

1. **Coordinating functions.** The functions to be coordinated with and among Reliability Coordinators and neighboring systems. (*The plan should include references to coordination of actions among neighboring systems and Reliability Coordinators when the plans are implemented*.)
2. **Fuel supply.** An adequate fuel supply and inventory plan which recognizes reasonable delays or problems in the delivery or production of fuel, fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil, and a plan to optimize all generating sources to optimize the availability of the fuel, if fuel is in short supply.
3. **Environmental constraints.** Plans to seek removal of environmental constraints for generating units and plants.
4. **System energy use.** The reduction of the system's own energy use to a minimum.
5. **Public appeals.** Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.
6. **Load management.** Implementation of load management and voltage reductions.

7. **Appeals to large customers.** Appeals to large industrial and commercial customers to reduce non-essential energy use and start any customer-owned backup generation.
8. **Interruptible and curtailable loads.** Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.
9. **Maximizing generator output and availability.** The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.
10. **Notifying IPPs.** Notification of co-generation and independent power producers to maximize output and availability, depending on tariff and contractual requirements.
11. **Load curtailment.** A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community.
12. **Notification of government agencies.** Notification of appropriate government agencies as the various steps of the emergency plan are implemented
13. **Notification.** Notification should be made to other operating entities as the steps of the emergency plan are implemented.

Measuring Processes

Periodic Review
The Regional Reliability Councils shall review and evaluate emergency plans every three years to ensure that as a minimum they address the **“**Functional Areas of a Capacity and Energy Emergency Plan.” listed in the Compliance Assessment notes.

Self-Assessment
The Regional Reliability Council may elect to conduct yearly checks of the CONTROL AREA or OPERATING AUTHORITY that may take the form of a self-certification document in years that the full review is not done.

100% Compliance

A Capacity and Energy Emergency plan consistent with the **“**Functional Areas of a Capacity and Energy Emergency Plan.” listed in the Compliance Assessment notes has been developed and is current.

Levels of Non-Compliance

Level 1 — One of the applicable “Functional Areas of a Capacity and Energy Emergency Plan” has not been addressed in the emergency plans.

Level 2 — Two of the applicable “Functional Areas of a Capacity and Energy Emergency Plan” have not been addressed in the emergency plans.

Level 3 **—** Three of the applicable “Functional Areas of a Capacity and Energy Emergency Plan” have not been addressed in the emergency plans.

Level 4 — Four or more of the applicable “Functional Areas of a Capacity and Energy Emergency Plan” have not been addressed in the emergency plans or a plan does not exist.

Compliance Reset Period

One calendar year

Data Retention Period

The CONTROL AREA or OPERATING AUTHORITY shall have its Capacity and Energy Emergency Plans available for a review by the Regional Reliability Council at all times

The CONTROL AREA or OPERATING AUTHORITY must have the information from their last two annual self-assessments available for a review by the Regional Reliability Council at all times

Monitoring Period

One calendar year

Reporting Period

Each calendar year

Reliability Principle 4 Plans for emergency operation and system restoration of interconnected BULK ELECTRIC SYSTEMS shall be developed, coordinated, maintained and implemented.

Section Policy 6, Section D (Draft 7 dated 3/11/2004 of the ORS-RCWG proposed revision)

Standard

Each OPERATING AUTHORITY shall develop and annually review its plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shut down of the system. (NERC Reference Document — Electric System Restoration)

Monitoring Responsibility

Regional Reliability Councils (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Applicable to

OPERATING AUTHORITIES

Measure

The Restoration Plan must address the requirements listed below, and must have provisions to simulate or physically test the plan.

Compliance Assessment Notes

The Restoration Plan must meet the following requirements:

1. Plan and procedures outlining the relationships and responsibilities of the personnel necessary to implement system restoration.
2. The provision for reliable black-start capability plan including: fuel resources for black start power for generating units, available cranking and transmission paths, and communication adequacy and protocol and power supplies.
3. The plan must account for the possibility that restoration cannot be completed as expected.
4. The necessary operating instructions and procedures for synchronizing areas of the system that have become separated.
5. The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.
6. A set of procedures for annual review and updated for simulating and, where practical, actual testing and verification of the plan resources and procedures (*at least every three years*).
7. Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.
8. The functions to be coordinated with and among reliability coordinators and neighboring systems. (*The plan should include references to coordination of actions among neighboring systems and reliability coordinators when the plans are implemented.)*
9. Notification shall be made to other operating entities as the steps of the restoration plan are implemented

Measuring Process

Periodic Review
Included as part of the on-site operational review every three years.

Self-Assessment
Annual report to the Regional Reliability Council of plan review and/or updates.

100% Compliance

The OPERATING AUTHORITY has developed and annually reviews their plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shut down of the system.

Levels of Non-Compliance

Level 1 — Plan exists but is not reviewed annually.

Level 2 — Plan exists but does not address one of the nine requirements.

Level 3 — N/A

Level 4 — Plan exists but does not address two or more of the nine requirements or there is no Restoration Plan in place.

Compliance Reset Period

One calendar year

Data Retention Period

The OPERATING AUTHORITY must have its plan to reestablish its electric system available for a review by the Regional Reliability Council at all times.

Monitoring Period

One calendar year

Reliability Principle 4 Plans for emergency operation and system restoration of interconnected BULK ELECTRIC SYSTEMS shall be developed, coordinated, maintained, and implemented.

Reliability Principle 5 Facilities for communications, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected BULK ELECTRIC SYSTEMS

Brief Description Emergency Operations/Loss of primary Controlling Facility

Section Policy 6, Section E

Standard

Each RELIABILITY COORDINATOR, CONTROL AREA, and other ERRIS identified by Regional Reliability Councils shall develop and keep current, a written contingency plan to continue to perform those functions necessary to maintain BULK ELECTRICAL SYSTEM reliability, in the event its Primary Control Facility becomes inoperable.

Applicable to

RELIABILITY COORDINATORS, CONTROL AREAS, and other ERRIS identified by Regional Reliability Councils.

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process. Some information contained in this plan is critical to the energy infrastructure and will be handled and treated accordingly.

Measure

The RELIABILITY COORDINATOR, CONTROL AREA, and other ERRIS identified by Regional Reliability Councils must have developed, documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain BULK ELECTRICAL SYSTEM reliability if their Primary Control Facility becomes inoperable.

Compliance Assessment Notes
Interim provisions must be included if it is expected to take in excess of one hour to implement the loss of Primary Control Facility contingency plan.

The contingency plan must meet the following requirements:

1. The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.

2. The plan shall include procedures and responsibilities for providing basic tie line control and procedures and responsibilities for maintaining the status of all inter area schedules such that there is an hourly accounting of all schedules.

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.

4. The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other control areas.

5. The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.

6. The plan shall include procedures and responsibilities for providing annual training to ensure that Shift Operating personnel are able to implement the contingency plans.

7. The plan shall be reviewed and updated annually.

Measuring Processes

Periodic Review
Review and evaluate the loss of Primary Control Facility contingency plan as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the RELIABILITY COORDINATOR, CONTROL AREA, or other ERRIS identified by Regional Reliability Councils.

Self-Certification
Each RELIABILITY COORDINATOR, CONTROL AREA, or other ERRIS must annually, self-certify to the RRC that Requirements 5, 6 and 7 have been done, that is, the Plan has been tested, the Shift Operators have been trained as planned, and the Plan has been reviewed.

Any significant changes to the contingency plan must be reported to the Regional Reliability Council (RRC).

100% Compliance

The RELIABILITY COORDINATOR, CONTROL AREA, and other ERRIS identified by Regional Reliability Councils has developed a contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain BULK ELECTRICAL SYSTEM reliability if their Primary Control Facility becomes inoperable. The contingency plan meets Requirements 1–7.

Levels of Non-Compliance

Level 1 — N/A

Level 2 — A contingency plan has been implemented and tested, but has not been reviewed in the past year, or the contingency plan has not been tested in the past year or there are no records of Shift Operating personnel training.

Level 3 — A contingency plan has been implemented, but does not include all of the elements contained in Requirements 1–4.

Level 4 — A contingency plan has not been developed, implemented, and tested.

Compliance Reset Period

One calendar year without a violation

Data Retention Requirements

The contingency plan for loss of Primary Control Facility must be available for review at all times.

Measurement Period

One calendar year

Reliability Principle	Personnel responsible for planning and operating interconnected BULK ELECTRIC SYSTEMS shall be trained, qualified, and have the responsibility and authority to implement actions.
Brief Description	Operating Personnel and Training/Responsibility and Authority
Section	Policy 8, Section A

Standard

The SYSTEM OPERATOR must have the responsibility and authority to implement real-time actions that ensure the stable and reliable operation of the BULK ELECTRIC SYSTEM.

Applicable to

OPERATING AUTHORITIES

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

The SYSTEM OPERATOR responsibility and authority to implement real-time actions that ensures the stable and reliable operation of the BULK ELECTRIC SYSTEM is documented and understood.

Compliance Assessment Notes

The following requirements must be met:

Documentation

1. A written current job description exists which states in clear and unambiguous language the responsibilities and authorities of a SYSTEM OPERATOR. The job description also identifies SYSTEM PERSONNEL subject to the authority of the SYSTEM OPERATOR.
2. Written current job description states the SYSTEM OPERATOR'S responsibility to comply with the *NERC Operating Policies.*
3. Written current job description is readily accessible in the control room environment to all SYSTEM OPERATORS.
4. Written operating procedures state that during normal operating conditions, the SYSTEM OPERATOR has the authority to take or direct timely and appropriate real-time actions without obtaining approval from higher level personnel within the SYSTEM OPERATOR'S own OPERATING AUTHORITY.
5. Written operating procedures state that during emergency conditions the SYSTEM OPERATOR has the authority to take or direct timely and appropriate real-time actions, up to and including shedding of firm load to prevent or alleviate SYSTEM OPERATING LIMIT violations. These actions are performed without obtaining approval from higher-level personnel within the SYSTEM OPERATOR'S own OPERATING AUTHORITY.

Interview Verification

1. Interviews with SYSTEM OPERATORS confirm that they have the authority to implement actions during normal and emergency conditions. The actions can be performed without seeking approval from higher-level personnel within the SYSTEM OPERATOR'S own OPERATING AUTHORITY.
2. Interviews and/or questionnaires with SYSTEM PERSONNEL, whose actions are directed by the SYSTEM OPERATOR, acknowledge the responsibility and authority of the SYSTEM OPERATOR.

Measuring Processes

Periodic Review
An on-site review including interviews with SYSTEM OPERATORS and documentation verification will be conducted every three years. The job description that identifies the SYSTEM OPERATOR'S authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of a SYSTEM OPERATOR to take actions necessary to maintain the reliability of the BULK ELECTRIC SYSTEM during normal and emergency conditions.

Self-certification
The OPERATING AUTHORITY will annually complete a self-certification form developed by the RRC based on requirements 1–5 in the Compliance Assessment Notes.

Levels of Non-Compliance

Level 1 — The OPERATING AUTHORITY has written documentation that includes four of the five items in the Compliance Assessment Notes (Items 1–5).

Level 2 — The OPERATING AUTHORITY has written documentation that includes three of the five items in the Compliance Assessment Notes (Items 1–5).

Level 3 — The OPERATING AUTHORITY has written documentation that includes two of the five items in the Compliance Assessment Notes (Items 1–5).

Level 4 — The OPERATING AUTHORITY has written documentation that includes only one or none of the five items in the Compliance Assessment Notes (Items 1–5) or the Interview Verification items 1 and 2 do not support the SYSTEM OPERATOR authority.

Compliance Reset Period

One calendar year

Data Retention Period

Permanent

Monitoring Period

One calendar year

Reliability Principle Personnel responsible for planning and operating interconnected BULK ELECTRIC SYSTEMS shall be trained, qualified, and have the responsibility and authority to implement actions.

Brief Description Operating Personnel and Training/OPERATING AUTHORITIES shall staff required operating positions with NERC-Certified SYSTEM OPERATORS.

Section Policy 8, Section C

Standard

An OPERATING AUTHORITY that maintains a control center(s) for the real-time operation of the interconnected BULK ELECTRIC SYSTEM shall staff operating positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected BULK ELECTRIC SYSTEM, and positions that are directly responsible for complying with *NERC Operating Policies, w*ith NERC-Certified SYSTEM OPERATORS.

Applicable to

OPERATING AUTHORITIES

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

The OPERATING AUTHORITY must have NERC-Certified SYSTEM OPERATOR(S) on shift in required positions as identified in the Standard, at all times with the following exceptions:

Exception (1) — While in training, an individual without the proper NERC certification credential may not independently fill a required operating position. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-Certified individual filling the required position.

Exception (2) — During a real-time operating emergency, the time when control is transferred from a primary control center to a backup control center shall not be included in the calculation of non-compliance. This time shall be limited to no more than four (4) hours.

Measuring Processes

Periodic Review
An on-site review will be conducted every three years. Staffing schedules and Certification numbers will be compared to ensure that positions that require NERC-Certified SYSTEM OPERATORS were covered as required. Certification numbers from the OPERATING AUTHORITY will be compared with NERC records.

Exception Reporting
Any violation of the standard must be reported to the RRC who will inform the NERC Vice President-Compliance, indicating the reason for the non-compliance and the mitigation plans taken.

Levels of Non-Compliance

Level 1 — The OPERATING AUTHORITY did not meet the requirement for a total time greater than 0 hours and up to 12 hours during a one calendar month period for each required position in the staffing plan.

Level 2 — The OPERATING AUTHORITY did not meet the requirement for a total time greater than 12 hours and up to 36 hours during a one calendar month period for each required position in the staffing plan.

Level 3 — The OPERATING AUTHORITY did not meet the requirement for a total time greater than 36 hours and up to 72 hours during a one-month calendar period for each required position in the staffing plan.

Level 4 — The OPERATING AUTHORITY did not meet the requirement for a total time greater than 72 hours during a one calendar month period for each required position in the staffing plan.

Compliance Reset Period

One calendar month without a violation.

Data Retention Period

Present calendar year plus previous calendar year staffing plan.

Monitoring Period

One calendar month

Principle Personnel responsible for planning and operating interconnected BULK ELECTRIC SYSTEMS shall be trained, qualified, and have the responsibility and authority to implement actions.

Brief Description Operating Personnel and Training/Training Program

Section Policy 8, Section B, Requirements 1, 1.1 — 1.7, Appendix B1

Standard

Each OPERATING AUTHORITY must develop, maintain and use a SYSTEM OPERATOR Shift Staff Training Program that is designed to promote reliable operation.

Applicable to

OPERATING AUTHORITY

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

The SYSTEM OPERATOR Shift Staff Training Program will be reviewed to ensure that it is designed to promote reliable operation.

Compliance Assessment Notes

The SYSTEM OPERATOR Shift Staff Training Program must meet the following requirements:

1. Documentation
    - 1.1. Objectives — A set of Training Program objectives must be defined, based on NERC Operating Policies, Regional Council policies, entity operating procedures, and applicable regulatory requirements.

      These objectives shall reference the knowledge and competencies needed to apply those policies, procedures, and requirements to normal, emergency, and restoration conditions for the shift operating positions.
    - 1.2. Initial and Continuing Training — The Training Program must include a plan for the initial and continuing training of SYSTEM OPERATOR Shift Staff that addresses required knowledge and competencies and their application in system operations.
    - 1.3. Training time — The Training Program must include training time for all SYSTEM OPERATOR Shift Staff to ensure their operating proficiency.
    - 1.4. Training staff — Trainers must be identified, and they must be individuals competent in both knowledge of system operations and instructional capabilities.
    - 1.5. Policy 8 — Training program must include elements of Policy 8 appendix 8B1 that apply to each specific SYSTEM OPERATOR Shift position.
2. At least five days per year of training and drills in system emergencies, using realistic simulations must be included in the SYSTEM OPERATOR Shift Staff Training Program.

Measuring Processes

Periodic Review
The Regional Reliability Council will conduct an on-site review of the SYSTEM OPERATOR Shift Staff Training Program every three years. The SYSTEM OPERATOR Shift Staff Training records will be reviewed and assessed against the SYSTEM OPERATOR Shift Staff Training Program.

Self-certification
The OPERATING AUTHORITY will annually provide a self-certification based on the requirement 1 and 2.

100% Compliance

The OPERATING AUTHORITY has developed and maintains a SYSTEM OPERATOR Shift Staff Training Program that includes the Requirement 1 criteria, and the Requirement 2 training has been completed.

Levels of Non-Compliance

Level 1 — N/A

Level 2 — The SYSTEM OPERATOR Training Program does not include all five requirements under Documentation, Requirement 1, in the Compliance Assessment Notes.

Level 3— All of the SYSTEM OPERATORS have not completed Requirement 2 training under the Compliance Assessment Notes.

Level 4 — A SYSTEM OPERATOR Shift Staff Training Program has not been developed.

Compliance Reset Period

One calendar year

Data Retention Period

Three years

Monitoring Period

One calendar year

Reliability Principle 7

The security of the interconnected BULK ELECTRIC SYSTEMS shall be assessed, monitored, and maintained on a wide-area basis.

Wide-area is the entire RELIABILITY COORDINATOR AREA as well as that critical flow and status information from adjacent RELIABILITY COORDINATOR AREAS as determined by detailed system (analysis or studies) to allow the calculation of INTERCONNECTION RELIABILITY OPERATING LIMITS.

Brief Description

RELIABILITY COORDINATOR Procedures including next day Operations Planning

Section

Policy 9 (Draft 7 dated 3/11/04 of the ORS-RCWG proposed revisions) Section D, Requirements 1, 2, 3 and 4

Standard

Each RELIABILITY COORDINATOR shall conduct next-day reliability analyses for its RELIABILITY COORDINATOR AREA to ensure the bulk power system can be operated reliably in anticipated normal and contingency event conditions. System studies shall be conducted to highlight potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc., and plans developed to alleviate SOL and IROL violations.

Applicable to

RELIABILITY COORDINATORS

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

The RELIABILITY COORDINATOR shall conduct next-day contingency analyses for its RELIABILITY COORDINATOR AREA to ensure that the BULK ELECTRIC SYSTEM can be operated reliably in anticipated normal and contingency event conditions.

Compliance Assessment Notes

Requirements:

1. The RELIABILITY COORDINATOR shall conduct contingency studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc. The 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.

2. The RELIABILITY COORDINATOR shall, in conjunction with its OPERATING 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.

Supporting Information
RELIABILITY COORDINATOR shall request from OPERATING AUTHORITIES in the RELIABILITY COORDINATOR AREA 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.

Measuring Processes

Periodic Review
Entities will be selected for on-site audit at least every three years. For a selected 30-day period, in the previous three calendar months prior to the on site audit, RELIABILITY COORDINATORS will be asked to provide documentation showing that next-day security analyses were conducted each day to ensure the bulk power system could be operated in anticipated normal and contingency conditions. Also, that they identified potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc

Self-Certification
Each RELIABILITY COORDINATOR must annually, self-certify compliance to its RRC to the Requirements 1 and 2 of the Compliance Assessment Notes.

Exception Reporting
RELIABILITY COORDINATORS will prepare a monthly report to the Regional Reliability Council, for each month that Requirement 1 System Studies were not conducted indicating the dates that studies were not done and the reason why.

Levels of Non-Compliance

Level 1 — Requirement 1 System Studies were not conducted for one day in a calendar month and/or the Requirement 2 Action Plans were not developed to maintain transmission loading within acceptable limits for potential interface and other INTERCONNECTED RELIABILITY OPERATING LIMIT violations.

Level 2 — Requirement 1 System Studies were not conducted for 2-3 days in a calendar month and/or the Requirement 2 Action Plans were not developed to maintain transmission loading within acceptable limits for potential interface and other INTERCONNECTED RELIABILITY OPERATING LIMIT violations.

Level 3 — Requirement 1 System Studies were not conducted for 4-5 days in a calendar month and/or the Requirement 2 Action Plans were not developed to maintain transmission loading within acceptable limits for potential interface and other INTERCONNECTED RELIABILITY OPERATING LIMIT violations.

Level 4 — Requirement 1 System Studies were not conducted for more than 5 days in a calendar month and/or the Requirement 2 Action Plans were not developed to maintain transmission loading within acceptable limits for potential interface and other INTERCONNECTED RELIABILITY OPERATING LIMIT violations.

Compliance Reset Period

One year without a violation from the time of the violation.

Data Retention Period

Documentation shall be available for 3 months that provides verification that system studies were performed as required.

Monitoring Period

One calendar month

Reliability Principle 7 The security of the interconnected BULK ELECTRIC SYSTEMS shall be assessed, monitored, and maintained on a wide-area basis.

Brief Description RELIABILITY COORDINATOR Procedures/Implementing Transmission system relief

Section Policy 9 (Draft 7 dated 3/11/04 of the RCWG proposed revisions)
Section F, Requirement 3 including all sub-requirements
Appendix C1, Section A, Requirement 5
Appendix C1, Section A, Requirement 4 4.3

Standard

A RELIABILITY COORDINATOR must take appropriate actions in accordance with established policies, procedures, authority and expectations, to relieve transmission loading including notifying appropriate RELIABILITY COORDINATORS and OPERATING AUTHORITIES to curtail INTERCHANGE TRANSACTIONS.

Applicable to

RELIABILITY COORDINATORS

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

If required, an investigation will be conducted to determine if appropriate actions were taken in accordance with established policies, procedures, authority and expectations, to relieve transmission loading including notifying appropriate RELIABILITY COORDINATORS and OPERATING AUTHORITIES to curtail INTERCHANGE TRANSACTIONS.

Compliance Assessment Notes

The Reliability Coordinator must follow the following requirements when relief of transmission congestion is required:

1. Implementing relief procedures. If transmission loading progresses or is projected to violate a SOL or IROL, the RELIABILITY COORDINATOR will perform the following procedures as necessary:

   1.1. Selecting transmission loading relief procedure. The RELIABILITY COORDINATOR experiencing a potential or actual SOL or IROL violation on the transmission system 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, such as those listed in Appendix 9C1, 9C2, or 9C3.

   1.2. Using local transmission loading relief procedure. The RELIABILITY COORDINATOR may use local transmission loading relief or congestion management procedures, provided the TRANSMISSION OPERATING ENTITY experiencing the potential or actual SOL or IROL violation is a party to those procedures.

1.3. Using a local procedure with an INTERCONNECTION-wide procedure. A RELIABILITY COORDINATOR may implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, the RELIABILITY COORDINATOR is obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY COORDINATOR desires to use a local procedure as a substitute for curtailments as directed by the INTERCONNECTION-wide procedure, it may do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee.

1.4. Complying with procedures. When implemented, all RELIABILITY COORDINATORS shall comply with the provisions of the INTERCONNECTION-wide procedure. This may include action by RELIABILITY COORDINATORS in other INTERCONNECTIONS to for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.

1.5. Complying with interchange policies. During the implementation of relief procedures, and up to the point that emergency action is necessary, RELIABILITY COORDINATORS and OPERATING AUTHORITIES shall comply with the Requirements of Policy 3, Section C, “Interchange Scheduling Standard.”

For the Eastern Interconnection, TLR Procedure notification documentation, operator logs of sink and neighbor CONTROL AREAS as well as related electronic communications are subject to field review.

Measuring Processes

Investigation
The RRC or NERC may initiate an investigation if there is a complaint that an entity has not implemented relief procedures in accordance with the requirements identified in the Compliance Assessment Notes.

100% Compliance

The RELIABILITY COORDINATOR implemented relief procedures in accordance with the requirements.

Levels of Non-Compliance

Level 1 — N/A

Level 2 — N/A

Level 3 — N/A

Level 4 — The RELIABILITY COORDINATOR did not implement loading relief procedures in accordance with the requirements identified in the Compliance Assessment Notes.

Compliance Reset Period

One month without a violation

Data Retention Period

One calendar year

Monitoring Period

One calendar year

Reliability Principle 7 The security of the interconnected BULK ELECTRIC SYSTEMS shall be assessed, monitored, and maintained on a wide-area basis.

Brief Description RELIABILITY COORDINATOR Procedures/Current Day Operations-Authority to Implement Emergency Procedures

Section Policy 9 (Draft 7 dated 3/11/04 of the ORS-RCWG proposed revisions) Section F, Requirement 2

Standard

RELIABILITY COORDINATORS must have the authority to immediately direct OPERATING AUTHORITIES within their RELIABILITY COORDINATOR AREA to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state.

Applicable to

RELIABILITY COORDINATORS

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

Documentation must clearly show that the RELIABILITY COORDINATORS have the authority to immediately direct OPERATING AUTHORITIES within their RELIABILITY COORDINATOR AREA to re-dispatch generation, reconfigure transmission, manage interchange transactions, or reduce system demand to mitigate SOL and IROL violations to return the system to a reliable state.

Measuring Processes

Periodic Review
The Regional Reliability Council shall review the RC documentation and the agreements with OPERATING AUTHORITIES that delineates the RELIABILITY COORDINATOR authority to immediately direct actions of the OPERATING AUTHORITIES in its RELIABILITY COORDINATOR AREA to mitigate SOL and IROL violations to return the system to a reliable state.

100% Compliance

The RELIABILITY COORDINATOR has documented authority to immediately direct all the OPERATING AUTHORITIES in its RELIABILITY COORDINATOR AREA to take actions to mitigate SOL and IROL violations to return the system to a reliable state.

Levels of Non-Compliance

Level 1 — N/A

Level 2 — N/A

Level 3 — RELIABILITY COORDINATOR does not have documentation of agreements with all the OPERATING AUTHORITIES in their RELIABILITY COORDINATOR AREA to authenticate the RELIABILITY COORDINATOR authority.

Level 4 — The RELIABILITY COORDINATOR does not have the authority to direct all the OPERATING AUTHORITIES in its RELIABILITY COORDINATOR AREA to take actions to mitigate SOL and IROL violations to return the system to a reliable state.

Compliance Reset Period

One year without a violation from the time of the violation.

Data Retention Period

Documentation must be available at all times.

Monitoring Period

One year from when the on-site review was completed or the self-certification was received.

Reliability Principle 7	The security of the interconnected BULK ELECTRIC SYSTEMS shall be assessed, monitored, and maintained on a wide-area basis.
Brief Description	RELIABILITY COORDINATOR Procedures/ENERGY EMERGENCY ALERTS
Section	Policy 9, Appendix B, Section A (Proposed to be renumbered to Policy 5, Appendix C)

Standard

An ENERGY EMERGENCY ALERT may be initiated by a RELIABILITY COORDINATOR when the LOAD SERVING ENTITY (LSE) is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or the LSE cannot schedule the resources due to, for example, ATC limitations or transmission loading relief limitations. When an ENERGY EMERGENCY ALERT is initiated, the RELIABILITY COORDINATOR must notify all CONTROL AREAS and TRANSMISSION PROVIDERS in his RELIABILITY COORDINATOR AREA, and the other RELIABILITY COORDINATORS. (RC notification is done via the RCIS.)

Applicable to

RELIABILITY COORDINATORS

Monitoring Responsibility

Regional Reliability Council (RRC). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Measure

An investigation will be done to determine if the issuance of an ENERGY EMERGENCY ALERT was done as per the standard and notifications were made.

Compliance Assessment Notes
Conference calls (e.g. NERC Hotline) between RELIABILITY COORDINATORS shall be held as necessary to communicate system conditions. The RELIABILITY COORDINATOR shall also notify the other RELIABILITY COORDINATORS when the Alert has ended.

Measuring Processes

Investigation
The RRC or NERC may initiate an investigation when an ENERGY EMERGENCY ALERT has been issued, or initiate an investigation to review the operation of days when CONTROL AREAS were near to or experiencing the interruption of firm load, to determine if an ENERGY EMERGENCY ALERT should have been issued but was not.

100% Compliance

The RELIABILITY COORDINATOR initiated the ENERGY EMERGENCY ALERT and completed notification as required by the Standard.

Levels of Non-Compliance

Level 1 — N/A

Level 2 — N/A

Level 3 — N/A

Level 4 — The RELIABILITY COORDINATOR did not issue an ENERGY EMERGENCY ALERT when required or did not meet the requirements of the Standard when an ENERGY EMERGENCY ALERT was issued.

Compliance Reset Period

One year without a violation from the time of the violation.

Data Retention Period

One calendar year

Monitoring Period

One calendar year

Brief Description Vegetation management program for transmission owners

Requirements

1. Each transmission owner shall have a vegetation management program to prevent transmission line contact with vegetation. The vegetation management program shall include the following elements:
   - Inspection requirements
   - Trimming clearances
   - Annual work plan
2. Each transmission owner shall report to its Regional Reliability Council all vegetation-related outages on transmission circuits 200 kV and higher and any other lower voltage lines designated by the RRC to be critical to the reliability of the electric system.

Applicable to

Transmission Owners

Reporting Requirements

Self-certification
The transmission owner annually self-certifies that it has performed vegetation program maintenance in the annual work plan according to the requirements and procedures contained in the program.

Periodic Reporting
Transmission owners shall report vegetation-related line outages on transmission circuits 200 kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system, to the Region for a calendar month by the 20th of the following month. The Region shall report quarterly results to NERC.

All outages shall be reported where the cause of the outage is the line faulting due to contact with vegetation, except:

- Multiple outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.
- A single trip followed by a successful automatic reclose within a 24-hour period shall not be a reportable outage.

Items to be Measured

1. The vegetation management program documentation contains the following elements:
   - Inspection requirements
   - Trimming clearances
   - Annual work plan
2. The transmission owner performs vegetation program maintenance in the annual work plan according to the requirements and procedures contained in the program.

3. All vegetation-related transmission line trips on lines of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system are reported.

Reporting Period

Three-year Audit
The Compliance Monitor will conduct an on-site review every three years. The Vegetation Management Program will be reviewed and assessed.

Self-Certification
The Transmission Owner annually submits a self-certification that it has performed all vegetation management maintenance in the annual work plan during the past calendar year that is described in the Vegetation Management Program.

Periodic Reporting
All vegetation-related transmission line trips on lines of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system will be reported to the region on a monthly basis by the 20th of the following month. The Region shall report quarterly results to NERC by the last business day of January, April, July, and October.

Full Compliance Requirements

Three-year Audit
The vegetation management program is fully documented and contains all three elements listed in Requirement 1 of items to be measured.

Self-Certification
The transmission owner performed all maintenance as described in the annual work plan.

Periodic Reporting
All vegetation-related transmission line outages of 200kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system are reported during a calendar quarter.

Non-Compliance

The transmission owner is non-compliant if:

- Vegetation-related outages occurred and were not reported during a one-month period
- The Vegetation Management Plan is found to be not complete
- The transmission owner did not perform necessary maintenance described in the annual work plan as reported via self-certification.

Compliance Reset Period

One calendar quarter

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description System performance under normal (no contingency) conditions.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S1. The interconnected transmission systems shall be planned, designed, and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet 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 (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

Measure

M1. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S1 are as defined in Category A (no contingencies) of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs),

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S1.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category A of Table 1 (no contingencies) that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category A.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agreed to by the Region):

1. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

2. Be conducted annually unless changes to system conditions do not warrant such analyses.
3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
4. Have established normal (pre-contingency) operating procedures in place.
5. Have all projected firm transfers modeled.
6. Be performed for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M1), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon:
   a. Including a schedule for implementation,
   b. Including a discussion of expected required in-service dates of facilities,
   c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

System performance under normal (no contingency) conditions.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

Table I. Transmission Systems Standards — Normal and Contingency Conditions[*]

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading Outages [c]
A - No Contingencies	All Facilities in Service	None	Applicable Rating [a] (A/R)	Applicable Rating [a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [f]: 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG or 3Ø Fault, with Normal Clearing [f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing [f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

[*] Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D [e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.
b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
d) Depending on system design and expected system impacts, the 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 may be necessary to maintain the overall security of the interconnected transmission systems.
e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.
g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Brief Description System performance following loss of a single bulk system element.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S2. The interconnected transmission systems shall be planned, designed, and constructed 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 (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category B of Table I (attached).

Measure

M2. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S2 contingencies are as defined in Category B (event resulting in the loss of a single element) of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs).

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S2.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category B contingencies that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category B,
5. Consider all contingencies applicable to Category B.

System Simulation Study/Testing Methods

System simulation studies/testing shall:

1. Be performed and evaluated only for those Category B contingencies that would produce the more severe system results or impacts:
   a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
   b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
5. Have all projected firm transfers modeled.
6. Be performed and evaluated for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category B contingencies.
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
11. Include the effects of existing and planned control devices.
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.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measure (M2), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon,
   a. Including a schedule for implementation,
   b. Including a discussion of expected required in-service dates of facilities,
   c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments supported by simulated system performance following loss of a single bulk system element.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan, as defined above, for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan, as defined above, for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Table I. Transmission Systems Standards — Normal and Contingency Conditions[*]

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading Outages[c]
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 7. Transmission Circuit 8. Transformer 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

[*] Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D [e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section --- 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) --- Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.
b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
d) Depending on system design and expected system impacts, the 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 may be necessary to maintain the overall security of the interconnected transmission systems.
e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.
g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Brief Description System performance following loss of two or more bulk system elements.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S3. The interconnected transmission systems shall be planned, designed, and constructed 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 maybe necessary to meet this standard.

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category C of Table I (attached).

Measure

M3. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S3 contingencies are as defined in Category C (event(s) resulting in the loss of two or more (multiple) elements element of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs).

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S3.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category C contingencies that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category C,

5. Consider all contingencies applicable to Category C.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agreed to by the Region):

1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts.
    a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
    b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
5. Have all projected firm transfers modeled.
6. Be performed and evaluated for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category C contingencies.
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
11. Include the effects of existing and planned control devices.
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.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measure (M3), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon,
    a. Including a schedule for implementation,
    b. Including a discussion of expected required in-service dates of facilities,
    c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments supported by simulated system performance following loss of two or more bulk system element.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan, as defined above, for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan, as defined above, for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Councils

Table I. Transmission Systems Standards — Normal and Contingency Conditions[*]

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading Outages[c]
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No

[*] Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D [e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) - Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.
b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
d) Depending on system design and expected system impacts, the 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 may be necessary to maintain the overall security of the interconnected transmission systems.
e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.
g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Brief Description System performance following extreme events resulting in the loss of two or more bulk system elements.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I (attached).

Measure

M4. Entities responsible for the reliability of the interconnected transmission systems shall assess the risks and system responses for Standard S4 as defined in Category D of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs),

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S4.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five),
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category D contingencies that addresses the plan year being assessed,
4. Consider all contingencies applicable to Category D.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agree to by the Region):

1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts:
   a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
   b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Have all projected firm transfers modeled.
5. Include existing and planned facilities.
6. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
8. Include the effects of existing and planned control devices.
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.

Corrective Plan Requirements

None required.

Reporting Requirements

The documentation of results of these reliability assessments shall annually be provided to the entities' respective NERC Region(s), as required by the Region.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments of system performance for extreme events (more severe than in I.A.M3) resulting in loss of two or more bulk system elements.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — A valid assessment, as defined above, for the near-term planning horizon is not available.

Level 2 — N/A

Level 3 — N/A

Level 4 — N/A

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Table I. Transmission Systems Standards — Normal and Contingency Conditions[*]

Category	Contingencies: Initiating Event(s) and Contingency Element(s)	Elements Out of Service	System Limits or Impacts: Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading Outages [c]
A - No Contingencies	All Facilities in Service	None	Applicable Rating [a] (A/R)	Applicable Rating [a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [f]: 1. Bus Section 2. Breaker (failure or internal fault)	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No
	SLG or 3Ø Fault, with Normal Clearing [f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing [f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No

[*] Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D [e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) - - - - - - - - - - Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.
b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
d) Depending on system design and expected system impacts, the 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 may be necessary to maintain the overall security of the interconnected transmission systems.
e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.
g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Brief Description Regional and interregional self-assessment reliability reports.

Category Assessment

Section I. System Adequacy and Security
B. Reliability Assessment

Standard

S1. The overall reliability (adequacy and security) of the Regions' interconnected bulk electric systems, both existing and as planned, shall comply with the NERC Planning Standards and each Region's respective Regional planning criteria.

Measure

M1. Each Region shall annually conduct reliability assessments of its respective existing and planned Regional bulk electric system (generation and transmission facilities) for:

1) Current year:
   - winter
   - summer
   - other system conditions as deemed appropriate by the Region
2) Near-term planning horizons (years one through five) detailed assessments shall be conducted.
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.
4) Interregional reliability assessments to ensure that the Regional bulk electric systems are planned and developed on a coordinated or joint basis.

Regional and interregional reliability assessments shall demonstrate that the performance of these systems is in compliance with NERC Standard I.A and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting adequacy and security.

Regional and interregional seasonal, near-term, and longer-term reliability assessments shall be provided to NERC on an annual basis.

In addition, special reliability assessments shall also be performed as requested by the NERC Planning Committee or Board of Trustees under their specific directions and criteria. Such assessments may include, but are not limited to:

- Security assessments
- Operational assessments
- Evaluations of emergency response preparedness
- Adequacy of fuel supply and hydro conditions
- Reliability impacts of new or proposed environmental rules and regulations
- 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.

Applicable to

Regional Reliability Councils

Items to be Measured

Annual Regional and interregional assessments of reliability for seasonal, near-term, and longer-term planning horizons, and special assessments as requested by other Regions or NERC.

Timeframe

Annually or as requested by NERC.

Levels of Non-Compliance

Level 1 — Regional, interregional, and/or special reliability assessments were provided as requested, but were incomplete.

Level 2 — N/A

Level 3 — N/A

Level 4 — Regional, interregional, and/or special reliability assessments were not provided.

Compliance Monitoring Responsibility

NERC

Brief Description Define and document disturbance monitoring equipment requirements.

Category Documentation and Implementation

Section I. System Adequacy and Security
F. Disturbance Monitoring

Standard

S1. Requirements shall be established on a Regional basis for the installation of disturbance monitoring equipment (e.g., sequence-of-event, fault recording, and dynamic disturbance recording equipment) that is necessary to ensure data is available to determine system performance and the causes of system disturbances.

Measure

M1. Each Region 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 Regional requirements shall include the following items:

Technical requirements:

1. Type of data recording capability (e.g., sequence-of-event, fault recording, dynamic disturbance recording).
2. Equipment characteristics including but not limited to:
   - recording duration requirements
   - time synchronization requirements
   - data format requirements
   - event triggering requirements
3. Monitoring, recording, and reporting capabilities of the equipment
   - voltage
   - current
   - frequency
   - MW and/or Mvar, as appropriate
4. Data retention capabilities
   (e.g., length of time data is to be available for retrieval)

Monitoring equipment location requirements:

5. Regional coverage requirements (e.g., by voltage, geographic area, electric area/subarea)
6. Installation requirements:
   - substations
   - transmission lines
   - generators

Testing and maintenance requirements:

7. Responsibility for maintenance and/or testing

Documentation requirements:

8. Requirements for periodic (at least every five years) updating, review, and approval of the Regional requirements

The Regional requirements shall be provided to other Regions and NERC on request (30 days).

Applicable to

Regions

Items to be Measured

Regional requirements for the installation of disturbance monitoring equipment.

Timeframe

On request by NERC (30 days).

Levels of Non-Compliance

Level 1 — The Region's disturbance monitoring requirements do not address one of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.

Level 2 — The Region's disturbance monitoring requirements do not address two of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.

Level 3 — The Region's disturbance monitoring requirements do not address three of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.

Level 4 — The Region's disturbance monitoring requirements were not provided or do not address four or more of the eight requirements for the installation of disturbance monitoring equipment as listed above under Measure M1.

Compliance Monitoring Responsibility

NERC

Brief Description Development of steady-state system models.

Category System models (steady-state)

Section II. System Modeling Data Requirements
A. System Data

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measure

M5. Each of the NERC Interconnections shall develop and maintain a library of solved (converged) steady-state system models. Models shall be developed for the near- and longer-term planning horizons that are representative of system conditions for projected seasonal peak, minimum, and other appropriate system demand levels. Within the Eastern Interconnection, the Regions shall coordinate and jointly develop the steady-state system models for that Interconnection.

Steady-state system models for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be developed annually for selected study years as determined by the Interconnection. The most recent solved (converged) steady-state models shall be provided to the Regions and NERC on request (30 days).

Applicable to

Regional Reliability Councils

Items to be Measured

Development of Interconnection steady-state system models.

Timeframe

Development of steady-state system models: annually.
Most recent steady-state system models: 30 days

Levels of Non-Compliance

An assessment of non-compliance will only be considered if a posting date is not met. Violations will not be assessed for Data Sets posted by the scheduled dates.

Level 1 — One of a Region's cases was either not submitted by the data submission deadlines, or was submitted by the data submission deadline but was not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

Level 2 — Two of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Level 3 — Three of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Level 4 — Four or more of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Compliance Monitoring Responsibility

NERC

Brief Description Development of dynamics system models.

Category System models (dynamics)

Section II. System Modeling Data Requirements
A. System Data

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measure

M6. Each of the Interconnections shall develop and maintain a library of initialized (with no faults or system disturbances) dynamics system models. Models shall be developed for at least two timeframes (present or near-term model and a future or longer-term model). Additional seasonal and demand level models shall be developed, as necessary, to analyze the dynamic response of each of the NERC Interconnections: Eastern, Western, and ERCOT. These dynamics system models shall be linked to the steady-state system models, as appropriate, of Standard II.A.M5. Within the Eastern Interconnection, the Regions shall coordinate and jointly develop the dynamics system models for that Interconnection.

Dynamics system models for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be developed annually for selected study years as determined by the Interconnection. The most recent initialized (approximately 25 seconds, no-fault) models shall be provided to the Regions and NERC on request (30 days).

Applicable to

Regional Reliability Councils

Items to be Measured

Development of Interconnection dynamics system models.

Timeframe

Development of dynamics system models: annually.
Most recent dynamics system models: on request (30 days).

Levels of Non-Compliance

An assessment of non-compliance will only be considered if a posting date is not met. Violations will not be assessed for Data Sets posted by the scheduled dates.

Level 1 — One of a Region’s cases was either not submitted by the data submission deadlines, or was submitted by the data submission deadline but was not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline.

Level 2 — Two of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Level 3 — Three of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Level 4 — Four or more of a Region's cases were either not submitted by the data submission deadlines, or were submitted by the data submission deadline but were not fully solved/ initialized or had other identified errors, or corrections were not submitted by the correction submittal deadline (or a combination thereof).

Compliance Monitoring Responsibility

NERC

Brief Description Methodology(ies) for determining electrical facility ratings.

Category Documentation

Section II. System Modeling Data Requirements
C. Facility Ratings

Standard

S1. Electrical facilities used in the transmission and storage of electricity shall be rated in compliance with applicable Regional requirements.

Measure

M1. Facility owners shall document the methodology(s) used to determine their electrical facility and equipment rating. Further, the methodology(s) shall be compliant with applicable Regional requirements.

The documentation shall address and include:

1. The methodology(s) used to determine facility and equipment rating of the items listed for both normal and emergency conditions:
   a. Transmission circuits
   b. Transformers
   c. Series and shunt reactive elements
   d. Terminal equipment (e.g., switches, breakers, current transformers, etc.)
   e. VAR compensators (SVC)
   f. High voltage direct current (HVDC) converters
   g. Any other device listed as a limiting element
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.
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.
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.
5. The documentation shall identify the assumptions used to determine each of the facility and equipment ratings, including references to industry rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal ratings and variations in assumptions shall be included.

The documentation of the methodology(s) used to determine transmission facility and equipment ratings shall be provided to the Regions and NERC on request (30 days).

Applicable to

Facility owners

Items to be Measured

Methodology(s) used for determining facility and equipment ratings.

Timeframe

On request (30 days).

Levels of Non-Compliance

Level 1 — Facility and equipment rating methodology(s) do not address one of the requirements listed in the above Measurement M1.

Level 2 — N/A

Level 3 — Facility and equipment rating methodology(s) do not address two of the requirements listed in the above Measurement M1.

Level 4 — Facility and equipment rating methodology(s) do not address three or more of the requirements listed in the above Measurement M1, or no facility and equipment rating methodology was provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Transmission Protection system maintenance and testing

Category Documentation and implementation

Section III. System Protection and Control
A. Transmission Protection Systems

Standard

S4. Transmission protection system maintenance and testing programs shall be developed and implemented.

Measure

M4. Transmission protection system owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:

a. Transmission Protection system identification shall include but are not limited to:
   - relays
   - instrument transformers
   - communications systems, where appropriate
   - batteries

b. Documentation of maintenance and testing intervals and their basis
c. Summary of testing procedure
d. Schedule for system testing
e. Schedule for system maintenance
f. Date last tested/maintained

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).

Applicable to

Transmission Protection system owner.

Items to be Measured

Documentation and implementation of transmission protection system maintenance and testing program.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 2 — Documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.

Compliance Monitoring Responsibility

Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Analysis and reporting of transmission protection misoperations.

Category Documentation of implementation

Section III. System Protection and Control
A. Transmission Protection Systems

Standard

S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.

Measurement

M5 Transmission protection system owners shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.

Documentation of the misoperation analyses and corrective actions shall be provided to the affected Regions and NERC on request (within 30 days) according to the Regional procedures of Measurement III.A. S3, M3.

Applicable to

Transmission protection system owners.

Items to be Measured

Documentation of protection system misoperations, analyses, and corrective actions.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1
Documentation of transmission protection system misoperations is complete according to Measurement III.A. S3, M3 but documentation of corrective actions taken for all identified misoperations is incomplete.

Level 2
Documentation of corrective actions taken for misoperations is complete but documentation of transmission protection system misoperations is incomplete according to Measurement III.A. S3, M3.

Level 3
Documentation of misoperations and corrective actions is incomplete.

Level 4
No documentation of misoperations or corrective actions was provided.

Compliance Monitoring Responsibility
Regions.

Reviewer Comments on Compliance Rating

Brief Description Development and documentation of Regional underfrequency load shedding (UFLS) programs coordinated within and among Regions.

Category Process, data, and assessment

Section III. System Protection and Control
D. Underfrequency Load Shedding

Standards

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measure

M1. Each Region shall develop, coordinate, and document a Regional UFLS program, which shall include the following:

1. Requirements for coordination of UFLS programs within the subregions, Region, and, where appropriate, among Regions.
2. Design details shall include, but are not limited to:
   a. size of coordinated load shedding blocks (% of connected load)
   b. corresponding frequency set points
   c. intentional and total tripping time delays
   d. related generation protection
   e. tie tripping schemes
   f. islanding schemes
   g. automatic load restoration schemes
   h. any other schemes that are part of or impact the UFLS programs
3. A Regional UFLS program database. This database shall be updated as specified in the Regional program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.
4. Technical assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This technical 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:
   a. A review of the frequency set points and timing, and
   b. Dynamic simulation of possible disturbance that cause the Region or portions of the Region to experience the largest imbalance between demand (load) and generation.

Documentation of each Region's UFLS program and its database information shall be provided to NERC on request (within 30 days). Documentation of the technical assessment of the UFLS program shall also be provided to NERC on request (within 30 days).

Applicable to

Regional Reliability Councils

Items to be Measured

The documentation and coordination of Regional UFLS programs.

Timeframe

On request by NERC (within 30 days) for the program, database, and results of technical assessments.

Levels of Non-Compliance

Level 1 — Documentation demonstrating the coordination of the Regional UFLS program was incomplete in one of the requirement~~s~~ in Measure M1.

Level 2 — N/A

Level 3 — N/A

Level 4 — Documentation demonstrating the coordination of the Regional UFLS program was incomplete in two or more requirements or documentation demonstrating the coordination of the Regional UFLS program was not provided, or an assessment was not completed in the last five years.

Compliance Monitoring Responsibility

NERC

Brief Description Assuring consistency of entity UFLS programs with Regional UFLS requirements.

Category Assessment

Section
III. System Protection and Control
D. Underfrequency Load Shedding

Standard

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measure

M2. Those entities owning or operating an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements as specified in Measure III.D.M1. Such entities shall provide and annually update their UFLS data as necessary for the Region to maintain and update an UFLS program as specified in Measure III.D.M1.

The documentation of an entity's UFLS program shall be provided to the Region on request (within 30 days).

Applicable to

Entities owning, operating, or required (by the Regions) to have an UFLS program.

Items to be Measured

Consistency of entity's UFLS program with Regional UFLS requirements.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Evaluations of entity UFLS programs for consistency with the Regional UFLS program were incomplete/inconsistent in one or more requirements of Measure III.D.M1 but is consistent with the required load shed.

Level 2 — The amount of load shedding is less than 95% of the regional requirements in any of the load steps.

Level 3 — The amount of load shedding is less than 90% of the regional requirements in any of the load steps.

Level 4 — The amount of load shedding is less than 85% of the regional requirements on any of the load steps, or evaluations of entity UFLS programs for consistency with the Regional UFLS program were not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Implementation and documentation of UFLS equipment maintenance program.

Category Documentation and implementation

Section III. System Protection and Control
D. Underfrequency Load Shedding

Standard

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measure

M3. UFLS equipment owners shall have an UFLS equipment maintenance and testing program in place. This program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

Applicable to

Entities owning, operating, or required (by Regions) to have UFLS equipment.

Items to be Measured

Documentation and implementation of UFLS equipment maintenance and testing program.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 2 — Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4 — Documentation of the maintenance and testing program, or its implementation was not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Analysis and documentation of UFLS program performance.

Category Assessment

Section III. System Protection and Control
D. Underfrequency Load Shedding

Standard

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measurement

M4. Those entities owning or operating UFLS programs shall analyze and document their UFLS program performance in accordance with Standard III.D. S1-S2, M1, including 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:

1) **A description of the event including initiating conditions**
2) **A review of the UFLS set points and tripping times**
3) **A simulation of the event**
4) **A summary of the findings**

Documentation of the analysis shall be provided to the Regions and NERC on request 90 days after the system event.

Applicable to

Entities owning, operating, or required (by the Regions) to have an UFLS program.

Items to be Measured

Analysis of UFLS program performance for underfrequency events below the UFLS set points.

Timeframe

On request 90 days after the system event.

Levels of Non-Compliance

Level 1
Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was incomplete in one or more requirements of Measurement M4.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
Analysis of UFLS program performance following an actual underfrequency event below the UFLS set point(s) was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

III. System Protection and Control
D. Underfrequency Load Shedding

G1. The UFLS programs should occur in steps related to frequency or rate of frequency decay as determined from system simulation studies. These studies are critical to coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration.

G2. The UFLS programs should be coordinated with generation protection and control, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control.

G3. The technical assessment of UFLS programs should include reviews of system design and dynamic simulations of disturbances that would cause the largest expected imbalances between customer demand and generation. Both peak and off-peak system demand levels should be considered. The assessments should predict voltage and power transients at a widespread number of locations as well as the rate of frequency decline, and should reflect the operation of underfrequency sensing devices. Potential system separation points and resulting system islands should be determined.

G4. Except for qualified automatic isolation plans, the opening of transmission interconnections by underfrequency relaying should be considered only after the coordinated load shedding program has failed to arrest system frequency decline and intolerable system conditions exist.

G5. A generation-deficient entity may establish an automatic islanding plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the transmission systems. This islanding plan may be used only if it complies with the Regional UFLS program and leaves the remaining interconnected bulk electric systems intact, in demand and generation balance, and with no unacceptable high voltages.

G6. In cases where area isolation with a large surplus of generation compared to demand can be anticipated, automatic generator tripping or other remedial measures should be considered to prevent excessive high frequency and resultant uncontrolled generator tripping and equipment damage.

G7. UFLS relay settings and the underfrequency protection of generating units as well as any other manual or automatic actions that can be expected to occur under conditions of frequency decline should be coordinated.

G8. The UFLS program should be separate, to the extent possible, from manual load shedding schemes such that the same loads are not shed by both schemes.

G9. Generator underfrequency protection should not operate until the UFLS programs have operated and failed to maintain the system frequency at an operable level. This sequence of operation is necessary both to limit the amount of load shedding required and to help the systems avoid a complete collapse. Where this sequence is not possible, UFLS programs should consider and compensate for any generator whose underfrequency protection is required to operate before a portion of the UFLS program.

G10. Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated.

If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or insertion reactors) should be implemented to minimize that probability.

If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

G11. Where the UFLS program fails to arrest frequency decline, generators may be isolated with local load to minimize loss of generation and enable timely system restoration.

Brief Description Technical assessment of the design and effectiveness of UVLS programs.

Category Assessment

Section III. System Protection and Control
E. Undervoltage Load Shedding

Standard

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.

Measure

M3. Those entities owning or operating UVLS programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of their UVLS programs.

This technical assessment shall include, but is not limited to:

- Coordination of the UVLS programs with other protection and control systems in the Region and with other Regions, as appropriate.
- Simulations that demonstrate that the UVLS programs performance is consistent with the I.A Standards.
- A review of the voltage set points and timing.

Documentation of the current UVLS technical assessment shall be provided to the appropriate Regions and NERC on request (30 days).

Applicable to

UVLS owners and operators.

Items to be Measured

Technical assessment of the design and effectiveness of UVLS programs.

Timeframe

Technical assessments every five years or as required by system changes.
Current technical assessment on request (30 days).

Levels of Non-Compliance

Level 1 — N/A

Level 2 — N/A

Level 3 — N/A

Level 4 — A technical assessment of the UVLS programs did not address one of the requirements listed in M3 above or a technical assessment of the UVLS programs was not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Under voltage load shedding system maintenance and testing.

Category Documentation and implementation

Section III. System Protection and Control
E. Under Voltage Load Shedding Systems

Standard

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

Measure

M4. Under voltage load shedding system owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:

a. Under voltage load shedding system identification shall include but is not limited to:
   - relays
   - instrument transformers
   - communications systems, where appropriate
   - batteries

b. Documentation of maintenance and testing intervals and their basis

c. Summary of testing procedure

d. Schedule for system testing

e. Schedule for system maintenance

f. Date last tested/maintained

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).

Applicable to

Under voltage load shedding system owner.

Items to be Measured

Documentation and implementation of under voltage load shedding system maintenance and testing program.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 2 — Compliance documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Analysis and documentation of UVLS program performance.

Category UVLS program performance

Section III. System Protection and Control
E. Undervoltage Load Shedding

Standard

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

Measurement

M5. Those entities owning or operating an UVLS program shall analyze and document all UVLS operations, misoperations, and failures to operate. Documentation of the analysis shall include a review of the UVLS set points and tripping times and a summary of the findings. This documentation shall be provided to the appropriate Regions and NERC on request (30 business days).

Applicable to

UVLS owners and operators.

Items to be Measured

Analysis of UVLS program performance.

Timeframe

On request (30 business days).

Levels of Non-Compliance

Level 1
An analysis of UVLS operations, misoperations, and failures to operate was provided but was incomplete.

Level 2
Not applicable.

Level 3
Not applicable.

Level 4
An analysis of UVLS program performance was not provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Notification and analysis of SPS misoperations and corrective action plans.

Category Documentation

Section III. System Protection and Control
F. Special Protection Systems

Standard

S4. All SPS misoperations shall be analyzed for cause and corrective action.

Measurement

M5. SPS owners shall analyze SPS operations and maintain a record of all misoperations in accordance with Regional procedures in Measurement III.F. S1-S4, M1. Corrective actions shall be taken to avoid future misoperations.

Documentation of the misoperation analyses and the corrective action plans shall be provided to the affected Regions and NERC, on request (within 90 days).

Applicable to

SPS owners.

Items to be measured

Documentation of SPS misoperations and corrective action plans.

Timeframe

On request (within 90 days of the incident or on request (within 30 days) if requested more than 90 days after the incident).

Levels of Non-Compliance

Level 1
Documentation of SPS misoperations is complete but documentation of corrective actions taken for all identified SPS misoperations is incomplete.

Level 2
Documentation of corrective actions taken for SPS misoperations is complete but documentation of SPS misoperations is incomplete.

Level 3
Documentation of SPS misoperations and corrective actions is incomplete.

Level 4
No documentation of SPS misoperations or corrective actions was provided.

Compliance Monitoring Responsibility
Regions.

Reviewer Comments on Compliance Rating

Brief Description Special Protection System maintenance and testing

Category Documentation and implementation

Section III. System Protection and Control
F. Special Protection Systems

Standard

S5. Special Protection System maintenance and testing programs shall be developed and implemented.

Measure

M6. Special Protection System owners shall have a system maintenance and testing program(s) in place. The program(s) shall include:

a. Special Protection System identification shall include but is not limited to:
   - relays
   - instrument transformers
   - communications systems, where appropriate
   - batteries

b. Documentation of maintenance and testing intervals and their basis
c. Summary of testing procedure
d. Schedule for system testing
e. Schedule for system maintenance
f. Date last tested/maintained

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days).

Applicable to

Special Protection System owners whose special protection systems support the reliability of the bulk power electric system.

Items to be Measured

Documentation and implementation of Special Protection System maintenance and testing program.

Timeframe

On request (within 30 days).

Levels of Non-Compliance

Level 1 — Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

Level 2 — Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

Level 3 — Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

Level 4 — Documentation of the maintenance and testing program, or its implementation, was not provided.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Brief Description Establish, maintain, and document a Regional blackstart capability plan.

Category Documentation

Section IV. System Restoration
A. System Blackstart Capability

Standard

S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.

Measure

M1. Each Region shall establish and maintain a system blackstart capability plan, as part of an overall coordinated Regional system restoration plan, that shall include requirements for verification through analysis how system blackstart generating units shall perform their intended functions and shall be sufficient to meet system restoration plan expectations.

The blackstart capability plan shall include:

1. A requirement to have a database that contains all blackstart generators designated for use in a Restoration Plan within the respective areas and a requirement to update the database on an annual basis. The database shall include the name, location, MW capacity, type of unit, latest date of test, and starting method.
2. A requirement to demonstrate that blackstart units perform their intended functions as required in the Regional system restoration plan through simulation or testing. The blackstart plan must consider the availability of designated blackstart plan units and initial transmission switching requirements.
3. Blackstart unit testing requirements including, but not limited to:
   - Testing frequency (minimum of one third of the units each year).
   - Type of test required, including the requirement to start when isolated from the system
   - Minimum duration of tests
4. A requirement to review and update the Regional blackstart capability plan at least every five years.

Documentation of system blackstart capability plans shall be provided to NERC on request (30 days).

Applicable to

Regional Reliability Councils

Items to be Measured

A Regional plan for blackstart capability.

Timeframe

Current Regional blackstart capability plan: on request by NERC and other Regions (30 days).

Levels of Non-Compliance

Level 1 — N/A

Level 2 — The Region's blackstart generating unit capability plan was incomplete in one of the four requirements defined above in Measure M1.

Level 3 — N/A

Level 4 — The Region's blackstart generating unit capability plan was not provided, or incomplete in two or more of the four requirements defined above in Measure M1.

Compliance Monitoring Responsibility

NERC

Brief Description Documentation of blackstart generating unit test results.

Category Documentation and implementation

Section IV. System Restoration
A. System Blackstart Capability

Standard

S2. Each blackstart generating unit shall be tested to verify that it can be started and operated without being connected to the system.

Measure

M4. The blackstart generating unit owner or operator shall test the startup and operation of each system blackstart generating unit identified in the blackstart capability plan as required in the regional Blackstart Plan (Standard IV.A. S1, M1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met regional Blackstart Plan requirements. A unit cannot be considered a blackstart unit unless it has met the regional blackstart requirements. It is expected that if a unit fails a test, that unit will be fixed and retested within a timeframe established by the Region in accordance with the regional Blackstart Plan or that unit will no longer be considered blackstart.

Documentation of the test results of the startup and operation of each blackstart generating unit shall be provided to the Region and upon request to NERC.

Applicable to

Owners or operators of blackstart generating units.

Items to be Measured

Test results of the startup and operation of blackstart generating units.

Timeframe

Current test results: to the Region and upon request to NERC (30 days).

Levels of Non-Compliance

Level 1 — Startup and operation testing of each blackstart generating unit was performed but documentation was incomplete.

Level 2 — Not applicable.

Level 3 — Startup and operation testing of blackstart generating unit was only partially performed.

Level 4 — Startup and operation testing of each blackstart generating unit was not performed.

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violation to NERC via the NERC Compliance Reporting process.