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

Interchange Subcommittee Meeting

Wednesday, April 21, 2004 — 8 a.m.–5 p.m.
(Interchange Standards and Business Practices Meeting)

Thursday, April 22, 2004 — 8 a.m. to 5 p.m. (Interchange Subcommittee)
Friday, April 23, 2004 — 8 a.m. to noon (Interchange Subcommittee)

Hyatt Regency Islandia
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Agenda

1. Administrative **20 min.**

a. Welcome and Introductions – Chairman
b. Arrangements – Secretary
c. Quorum – Secretary
d. Procedures – Chairman
   i) Antitrust Compliance Guidelines
   ii) Parliamentary Procedures
e. OC Subcommittee Organization and Procedures – Secretary
f. Interchange Subcommittee Scope – Secretary
g. Minutes of February 2–4, 2004 Meeting – Chairman
h. Approval of Agenda – Chairman

2. August 14, 2003 Outage Investigations – Jim McIntosh **20 minutes**

a. Latest issues surrounding the blackout

3. Policy 3, Version 0 and Compliance Templates – Doug Hils **1 hour**

a. Accelerated transition to standards
   i) Interchange Subcommittee actions
b. Board of Trustees approve Policy 3 Compliance Templates

4. Dynamic Transfers – Doug Hils **2 hours**

a. Interchange Subcommittee letter to OC Chairman Mark Fidrych
   i) Operating Committee actions on dynamic transfers
b. Dynamic Transfer White paper revisions
   i) Proposed revisions from Mike Oatts, Mike Potishnak, Deanna Phillips

5. Dynamic Scheduling Problems – Monroe Landrum **1 hours**

a. Examples of dynamic scheduling problems
   i) John Calder – Dominion Power
   ii) Garth Arnott – NCEMC

6. AIE – E-Tag – EMS Survey and Dynamic Transfer Catalog – Gordon Scott **2 hours**

a. Proposed August 14 follow-up survey letter – Gordon Scott
b. Development of Dynamic Transfer Catalog – Bob Cummings

7. The Interchange Authority Function – John Simonelli **2 hours**

a. Version 0 and the IA Function
b. NERC Reliability Functional Model – Version 2 – TBD
c. Discuss “Interchange State” definitions and the Functional Model – Roman Carter
d. Discuss “Operating Authority Users Manual” for reliability and business standards – Al Boesch

8. IDC Granularity – Lanny Nickell **20 min.**

a. IDC Granularity White Paper

9. Policy 3 as Version 0 – Al Boesch **3 hours +**

a. Policy 3 reliability principles as Functional Model standards

10. Other Subcommittee Items **Time Permitting**

a. Scheduling Entity and Scheduling Agent E-Tag Fields

11. Future Meetings – Secretary **10 min.**

a. Calendar for 2004

Item 1. Administrative

a. Welcome and Introductions – Chairman

The chairman will welcome the group and request introductions.

The subcommittee will review the roster for revisions.

Attachment

Interchange Subcommittee Roster

b. Arrangements – Secretary

The secretary will review the meeting arrangements. The joint Interchange Subcommittee, Coordinate Interchange Standard Drafting Team, and Coordinate Interchange Standard and Business Practices Task Force meeting begins on Wednesday, April 21 at 8 a.m. and adjourns at 5 p.m. The Interchange Subcommittee will reconvene on Thursday, April 22 at 8 a.m. and will adjourn at 5 p.m. A luncheon will be served on Thursday. The subcommittee will reconvene on Friday, April 23 at 8 a.m. and will adjourn at noon.

c. Quorum – Secretary

The secretary will announce whether a quorum (50% of the voting members) is in place. NOTE: the subcommittee cannot conduct business without a quorum. Please be prepared to stay for the entire meeting.

d. Procedures – Chairman

The NERC Antitrust Compliance Guidelines and a summary of Parliamentary Procedures are attached for reference. The secretary will answer questions regarding these procedures.

Attachments

1d Antitrust Guidelines

1d Summary of Parliamentary Procedures

e. OC Subcommittee Organization and Procedures

A summary of OC Subcommittee Organization and Procedures is attached for reference. The secretary will answer questions regarding these procedures.

Attachment

OC Subcommittee Organization and Procedures

f. Interchange Subcommittee Scope

The Interchange Subcommittee scope is attached for reference. The secretary will answer questions regarding the scope.

Attachment

Interchange Subcommittee scope

g. Minutes of February 2–4, 2004 Meeting – Chairman

The chairman will ask for approval of the February 2–4, 2004 Interchange Subcommittee meeting minutes.

Attachment

Minutes of February 2–4, 2004 Interchange Subcommittee meeting

h. Approval of Agenda – Chairman

The chairman will announce agenda changes and ask for additional items from the subcommittee members.

Action

The chairman will ask for approval of the agenda.

Interchange Subcommittee

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Interchange Subcommittee

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NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or which might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. PROHIBITED ACTIVITIES

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees
June 14, 2002

III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Organization Standards Process Manual
- Transitional Process for Revising Existing NERC Operating Policies and Planning Standards
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

Parliamentary Procedures

Based on Robert's Rules of Order, Newly Revised, 10th Edition, plus "Organization and Procedures Manual for the NERC Standing Committees"

Motions

Unless noted otherwise, all procedures require a "second" to enable discussion.

When you want to…	Procedure	Debatable	Comments
Raise an issue for discussion	Move	Yes	The main action that begins a debate.
Revise a Motion currently under discussion	Amend	Yes	Takes precedence over discussion of main motion. Motions to amend an amendment are allowed, but not any further. The amendment must be germane to the main motion, and cannot reverse the intent of the main motion.
Reconsider a Motion already approved	Reconsider	Yes	Allowed only by member who voted on the prevailing side of the original motion.
End debate	Call for the Question *or* End Debate	No	If the Chair senses that the committee is ready to vote, he may say "if there are no objections, we will now vote on the Motion." Otherwise, this motion is not debatable and subject to 2/3 majority approval.
Record each member's vote on a Motion	Request a Roll Call Vote	No	Takes precedence over main motion. No debate allowed, but the members must approve by 2/3 majority.
Postpone discussion until later in the meeting	Lay on the Table	Yes	Takes precedence over main motion. Used only to postpone discussion until later in the meeting.
Postpone discussion until a future date	Postpone until	Yes	Takes precedence over main motion. Debatable only regarding the date (and time) at which to bring the Motion back for further discussion.
Remove the motion for any further consideration	Postpone indefinitely	Yes	Takes precedence over main motion. Debate can extend to the discussion of the main motion. If approved, it effectively "kills" the motion. Useful for disposing of a badly chosen motion that can not be adopted or rejected without undesirable consequences.
Request a review of procedure	Point of order	No	Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion.

Notes on Motions

Seconds. A Motion must have a second to ensure that at least two members wish to discuss the issue. The "seconder" is not recorded in the minutes. Neither are motions that do not receive a second.

Announcement by the Chair. The Chair should announce the Motion before debate begins. This ensures that the wording is understood by the membership. Once the Motion is announced and seconded, the Committee "owns" the motion, and must deal with it according to parliamentary procedure.

Voting

Voting Method	When Used	How Recorded in Minutes
Unanimous Consent	When the Chair senses that the Committee is substantially in agreement, and the Motion needed little or no debate. No actual vote is taken.	The minutes show "by unanimous consent."
Vote by Voice	The standard practice.	The minutes show Approved or Not Approved (or Failed).
Vote by Show of Hands (tally)	To record the number of votes on each side when an issue has engendered substantial debate or appears to be divisive. Also used when a Voice Vote is inconclusive. (The Chair should ask for a Vote by Show of Hands when requested by a member).	The minutes show both vote totals, and then Approved or Not Approved (or Failed).
Vote by Roll Call	To record each member's vote. Each member is called upon by the Secretary,, and the member indicates either "Yes," "No," or "Present" if abstaining.	The minutes will include the list of members, how each voted or abstained, and the vote totals. Those members for which a "Yes," "No," or "Present" is not shown are considered absent for the vote.

Notes on Voting
(Recommendations from DMB, not necessarily Mr. Robert)

Abstentions. When a member abstains, he is not voting on the Motion, and his abstention is not counted in determining the results of the vote. The Chair should not ask for a tally of those who abstained.

Determining the results. The results of the vote (other than Unanimous Consent) are determined by dividing the votes in favor by the total votes cast. Abstentions are not counted in the vote and shall not be assumed to be on either side.

"Unanimous Approval." Can only be determined by a Roll Call vote because the other methods do not determine whether every member attending the meeting was actually present when the vote was taken, or whether there were abstentions.

Majorities. Robert's Rules use a simple majority (one more than half) as the default for most motions. NERC uses 2/3 majority for all motions.

Approved by Operating Committee

July 11–12, 2001

OC Subcommittee Organization and Procedures

Introduction

This document explains the membership requirements and selection procedure for the Operating Committee's Subcommittees. Membership on Task Forces and Working Groups will remain as specified in the Standing Committees Organization and Procedures Manual, Section VI.

Background

NERC has very specific membership requirements for its Standing Committees to ensure that all industry segments as well as the Regional Councils are represented. However, subcommittees, task forces, and working group membership may be based on either "expertise" (with varying degrees of regard to industry segments) or on industry segments (with some regard to expertise), at the discretion of the parent Committee.

In reality, most Operating Committee subgroup members represent the Regional Councils, with emphasis on expertise in the subgroup's areas of responsibilities, and with some or little regard to industry segment representation. This may be acceptable for the membership of task forces and working groups. However, the Operating Committee's subcommittees have Operating Policy custodianship; therefore, subcommittee membership must encompass the various industry segments who are materially affected by the Operating Policies for which the subcommittee is responsible. This is in addition to the traditional Regional Council representation, which should continue.

Subcommittee Scope and Reporting

The Subcommittee will keep its Scope Document up to date. All Subcommittees report to the Operating Committee.

Operating Policies

The Subcommittee will follow NERC's Policy and Standards Development Process when posting new or revised Operating Policies for comment or Operating Committee ballot. The Subcommittee will respond to all public comments. The Subcommittee may request Operating Committee input and advice when preparing new or revised Operating Policies, but does not need Operating Committee approval to post Policies for comment or OC ballot.

Membership Criteria

The Resource, Transmission, Interchange, Security, and Interconnected Operations Services, Subcommittees shall comprise 19 members: nine system operators or transmission providers, nine transmission customers, plus a chairman who does not represent any industry segment or Regional Council.

The Personnel Subcommittee's primary focus is on System Operator training and certification and its membership should include expertise in these two areas. Regional Council training managers should be on the Personnel Subcommittee. The Subcommittee should also strive for participation from transmission customers, but an equal mix of operators and customers may not be feasible.

The Personnel Subcommittee is a bit different.

Furthermore, *all* Subcommittees shall include among their 18 members:

- At least one representative from each Interconnection.
- At least one representative from Canada

Expertise

Expertise in the subject of the Operating Policies for which the Subcommittee is responsible remains of prime importance.

Regional Council Representation

NERC's underpinnings remain the Regional Councils, and they have expressed a strong desire to continue to be represented on NERC Subcommittees. Therefore, Subcommittee membership must accommodate representatives from each of the 10 Regional Councils (if they desire such representation). This representation should be embodied in the Subcommittee 18 members.

Members from the same organization

Two subcommittee members may be from the same organization as long as one is a system operator or transmission provider and the other a transmission customer.

Current practice. Less restrictive than Standing Committees, but increases pool of experts to select from.

Members on multiple Subcommittees

Individuals should not serve on more than one Subcommittee if possible.

Current practice. In some cases, we have no choice.

Officers

The Subcommittee will have a chairman and a vice chairman. The chairman will not represent either the provider or customer segment, or a Regional Council. The Subcommittee vice chairman will be one of the 18 members, preferably from a different industry segment than the chairman.

Membership Selection

To fill a Subcommittee vacancy:

1. The NERC staff will solicit candidates from the Subcommittee officers, Standing Committee members, Regional Councils, and Trade Organizations as necessary.
2. The Subcommittee chairman will then select from that list sufficient candidates to fill the vacancies, keeping in mind the segment balance that must be maintained on the Subcommittee.
3. The NERC staff will send the recommended candidates to the Operating Committee chairman via e-mail for approval. The e-mail will include a brief biography of the candidate and current responsibilities. The staff will copy the OC and MIC Executive Committees for their comments.
4. The Operating Committee chairman will consider the comments offered by the Executive Committees and issue his decision within five days of the request.

Officer Selection

The NERC staff will solicit candidates from the Subcommittee officers, Standing Committee members, Regional Councils, and Trade Organizations as necessary. The Subcommittee officers will then be selected jointly by the Operating Committee and Market Interface Committee chairmen.

Meeting Procedures

Quorum

A quorum consists of 50% of the Subcommittee members listed on the current roster.

Voting

A two-thirds vote is required to adopt any motion. A two-thirds vote is based on the total votes cast. Abstentions are neither requested nor considered in calculating the two-thirds vote.

Subgroups

The Subcommittee may form Task Forces and Working Groups as necessary.

The Subcommittees may also form small Task Groups to assist in drafting Standards, processes, Reference Documents, and concept papers between regular Subcommittee meetings. These Task Groups would, in most cases, exist for a short time (usually less than a year), and report to the Subcommittee. (Task Forces and Working Groups may also form Task Groups for this purpose).

Open Meetings

Subcommittee meetings will be open to guests who register in advance. Subcommittee chairmen will ensure that guests have an opportunity to participate in the discussion. However, voting will be the responsibility of the Subcommittee members only.

Purpose

The Interchange Subcommittee develops, maintains, and oversees the implementation of Policies and Standards that provide for the movement of energy across the transmission network in a reliable and efficient manner.

Scope

The Interchange Subcommittee develops, maintains and oversees the implementation of the Policies, Standards and compliance requirements specifically related to:

1. Market requests to implement and/or modify physical transactions
2. Reliability requests to modify physical transactions
3. Implementation of the above requests as schedules.

The Interchange Subcommittee will also:

1. Assist in developing programs and facilities associated with the transfer of energy. This includes development of the business plan, including costs, and schedules for developing system projects and training.
2. Develop Metrics and Compliance Templates for performance measurement.
3. Assist the Personnel Subcommittee in developing training materials for system operators.

Operating Policies

1. Policy 3 “Interchange” and its Appendixes.
2. Responsible for policies and standards involving interchange.

Reporting

The Interchange Subcommittee reports to the NERC Operating Committee and shall maintain communications with the Market Interface Committee, Planning Committee, and other groups as necessary on relevant issues.

Membership

1. Eighteen members plus chairman.
2. Membership is divided equally between transmission providers/system operators and transmission customers.

Officers

Chairman and vice chairman, selected by the Operating Committee chairman and vice chairman. The chairman does not represent an industry sector. Both officers may vote.

Meeting Procedures

1. Quorum: 50% of Subcommittee members eligible to vote.
2. All other procedures follow those of the “Organization and Procedures Manual for the NERC Standing Committees.”

Subgroups

The Interchange Subcommittee may form Working Groups, Task Groups, and Task Forces as needed to assist the Subcommittee in carrying out standing or ad hoc assignments. Task Group chairmen (or delegates) are expected to attend the regular Subcommittee meetings to report on assignments.

1. **Transaction Information System Working Group.** Responsible for implementing NERC transaction information system. (See TISWG Scope.)

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Interchange Subcommittee Meeting

February 2–4, 2004
Scottsdale, Arizona

Minutes

A regular meeting of the Interchange Subcommittee was held on February 2–4, 2004 in Orlando, Florida. The meeting notice, agenda, and attendance list are affixed as **Exhibits A, B,** and **C**, respectively. Individual statements and minority opinions are affixed as **Exhibits D** and **E**. (There were none.)

Interchange Subcommittee Chairman Doug Hils presided. Chairman Hils summarized the NERC Antitrust Compliance Guidelines, which were included in the agenda.

The secretary reported that a quorum was present, and reviewed the Action Items and Issues List.

The subcommittee approved the meeting agenda.

Minutes of December 3–5, 2003 Meeting

The Interchange Subcommittee approved the December 3–5, 2003 meeting minutes.

NERC Blackout Recommendations

Jim McIntosh discussed the "NERC Recommendations to Prevent and Mitigate the Impacts of Future Cascading Blackouts." (**Presentation 1**) The subcommittee discussed the corrective actions NERC plans to undertake. There may be more recommendations as a result of the U.S./Canada Task Force's final report.

The subcommittee noted that some of the NERC recommendations are not supported by current policy, and discussed how current policy, or the new standards under development, could be modified to fit the recommendations. The subcommittee determined that dynamic scheduling might be the only issue that needs to be addressed by the Interchange Subcommittee at this time.

Bob Cummings, NERC director of reliability assessment & support services, presented the System Modeling and Simulation Analysis Team's findings of the August 14 tag audit (**Presentation 2**). Mr. Cummings provided an overview of the system studies and the problems encountered with accounting for dynamic transfers and jointly owned units. The team was charged with modeling and conducting transmission studies in the outage areas for those hours prior to the outage.

Mr. Cummings suggested that a peer review of dynamic schedules and pseudo-ties (a Dynamic Transfer Catalog) is needed to be able to analyze dynamic transfers. The catalog would allow for grouping of dynamic transfer characteristics and provide input into future policy changes.

Policy 3 and Dynamic Transfers

Joe Emde, NERC compliance group, provided an overview of the AIE audit that the Resources Subcommittee called for the hours before the August 14 outage. The tag audit showed large discrepancies caused by capacity transactions related to jointly owned generating units and remotely metered control area loads. Mr. Emde will forward the audit discrepancies to the subcommittee for review.

Action: The subcommittee formed a task group to review the audit discrepancies and determine if there were violations to Policy 3. If Policy 3 violations occurred, the NERC compliance group will be informed and letters on non-compliance issued. Task group members are: Al Boesch, John Simonelli, Jim McIntosh, Doug Hils, Alan Johnson, and Joe Emde.

Tim Ponseti, Tennessee Valley Authority, provided an overview of TVA's proposal to adjust the E-Tag audit. (**Presentation 3**) Mr. Ponseti made the following points:

- The IDC is not an accurate representation of scheduled transactions.
- The audit found 2,000 MW errors across multiple hours. These errors are not isolated to the August 14, 2003 outage.
- EMS and E-Tag systems are not in synch and dynamic transfers are not accurately scheduled.
- Control areas' ACE might be incorrectly calculated using incorrect schedules.
- Audits comparing IDC to E-Tag mask the problem between the IDC and EMS.
- When TLRs are called and E-Tags are not updated, the discrepancy between the E-Tags and EMS increases.

Mr. Ponseti believes that incorrect schedules in control areas' Energy Management Systems account for the high frequency on the Eastern Interconnection, and may account for the less than anticipated reductions when TLRs are called. TVA recommends that regular audits be required to compare E-Tag and EMS data.

Julie Novacek, IDC Working Group chair, noted that some pseudo-ties are not included in the IDC model. It is the Reliability Coordinator's responsibility to submit monthly model updates. Ms. Novacek also reported that the IDC Working Group has recommended to the Reliability Coordinator Working Group and Operating Reliability Subcommittee that the SDX be updated on an hourly basis. If approved by the ORS, this proposal will go to the Operating Committee for approval.

Dynamic Transfer White Paper

Doug Hils lead a discussion on the Dynamic Transfer White Paper. The subcommittee reviewed the comments to the current posting submitted by the CAISO, accepted most of those changes, added some edits, and submitted the comments to the posting. (**Presentation 4**)

Transaction Information Systems Working Group Report

Monroe Landrum, Transaction Information Systems Working Group chairman provided an update on the group's activities. Mr. Landrum reported that NERC would continue to maintain the Registry. A prototype of the revised registry is scheduled for testing this summer.

The subcommittee discussed a letter from GridAmerica that requests changing the definition of the Scheduling Agents to allow GridAmerica to use the Scheduling Entity field on the tag. As a Transmission Service Provider, GridAmerica wants to become a scheduling agent for the purpose of managing Transmission services for Northern Indiana Public Service Company and FirstEnergy. A previous waiver approved by the Operating Committee identifies MISO and PJM as Scheduling Agents.

Action: Doug Hils will send a letter to GridAmerica stating that the tag's primary purpose is to coordinate reliability data, and the subcommittee does not recognize a reliability reason for GridAmerica to use this field. In this letter, the subcommittee will invite a GridAmerica representative to present their case at next IS meeting. If GridAmerica chooses not to send a representative, then they should begin the process to end using the field.

Action: Review new registrations of scheduling entities at next meeting. Also review requirement to complete the scheduling entity field.

Compliance Templates

The group spent considerable time reviewing the current Policy 3 templates, revising the templates and drafting new templates. The subcommittee will provide these templates to the Compliance Template Task Group for review. (**Presentations 5 and 6a, 6b, 6c, 6d**)

Transition to NERC Standards

Mike Oatts, Al Boesch, and Roman Carter reviewed Standard 400 – Coordinate Interchange, and compared existing Policy 3 coverage with NAESB's proposed business practices. Areas were identified where existing policy is not covered in the new standards or proposed business practices. (**Presentations 7 and 8**)

OC Subcommittee Officers Meeting

Doug Hils noted that an OC Subcommittee Officers meeting is scheduled for February 19–20 and requested that subcommittee members submit items for that meeting agenda. The purpose of this meeting is to review the Operating Committee's 2004 Work Plan, ensure that the proper subgroups are identified to address the tasks in that Plan, and that those groups have rolled those tasks into their individual task lists. During this process, the IS will make sure there are no gaps or conflicts, look at the transition to the new reliability standards, the Functional Model, and coordination with NAESB, (Several NAESB subcommittee officers will be present to help.), and review subcommittee membership requirements, especially in light of NAESB's role in developing business practices and the loss of many transmission customers from our subcommittee rosters.

Future Meetings

The subcommittee reviewed the proposed meeting schedule for 2004.

2004 Dates	Location
February 2–4	Scottsdale, Arizona
April 21–23	San Diego, California
June 16–18	Toronto, Canada
September 13 – 15	Boston, Massachusetts
November 30–December 2	Ft. Lauderdale, Florida

Gordon L. Scott

Secretary
Interchange Subcommittee

Item 2. August 14 Outage Investigations – Jim McIntosh

Background

NERC continues to address the August 14 blackout and is following up on the **NERC Recommendations to Prevent and Mitigate the Impacts of Future Cascading Blackouts**. Jim McIntosh will review the progress made in addressing the NERC recommendations and discuss items related to other investigations of the blackout. [See NERC Recommendations: ftp://www.nerc.com/pub/sys/all_updl/docs/blackout/BOARD_APPROVED_BLACKOUT_RECOMMENDATIONS_021004.pdf]

The **U.S.-Canada Power System Outage Task Force Final Report** has been issued. NERC's response to the report follows:

The North American Electric Reliability Council (NERC) welcomes the U.S.-Canada Power System Outage Task Force Final Report on the August 14 Blackout. "NERC agrees with the task force that the single most important step that the United States Congress can take is to enact the reliability provisions in pending energy bills," stated Michehl R. Gent, NERC President and CEO. "We again urge Congress to pass reliability legislation this year," he added.

Mr. Gent also appreciates the report's recognition of and support for NERC's February 10, 2004, blackout recommendations. "NERC is taking significant steps to implement key recommendations approved by its independent board, and additional work to implement those recommendations is under way," Mr. Gent stated. "We have recently adopted revised compliance templates and new disclosure guidelines, initiated a series of rigorous control area readiness audits, and will soon ballot revisions to NERC operating policies that incorporate the findings of the blackout investigation team."

The NERC Steering Group will examine the government report in greater detail and determine how to incorporate aspects of the report into NERC's action plan. "NERC will work closely with the U.S.-Canada task force to ensure that all appropriate actions are implemented to prevent future cascading blackouts," Mr. Gent emphasized. [See U.S. Canada Outage Report: http://www.nerc.com/%7Efilez/blackout.html]

Action

The subcommittee should review the NERC recommendations and address any items that fall under the purview of the Interchange Subcommittee. The subcommittee will review the dynamic transfer secondary factor that may have contributed to the outage under agenda Item 4a.

Attachment

2 Blackout report recommendations

3. Causes of the Blackout and Violations of NERC Standards

Summary

This chapter explains in summary form the causes of the initiation of the blackout in Ohio, based on the analyses by the bi-national investigation team. It also lists NERC's findings to date concerning seven specific violations of its reliability policies, guidelines, and standards. Last, it explains how some NERC standards and processes were inadequate because they did not give sufficiently clear direction to industry members concerning some preventive measures needed to maintain reliability, and that NERC does not have the authority to enforce compliance with the standards. Clear standards with mandatory compliance, as contemplated under legislation pending in the U.S. Congress, might have averted the start of this blackout.

Chapters 4 and 5 provide the details that support the conclusions summarized here, by describing conditions and events during the days before and the day of the blackout, and explain how those events and conditions did or did not cause or contribute to the initiation of the blackout. Chapter 6 addresses the cascade as the blackout spread beyond Ohio and reviews the causes and events of the cascade as distinct from the earlier events in Ohio.

The Causes of the Blackout in Ohio

A dictionary definition of "cause" is "something that produces an effect, result, or consequence."[1] In searching for the causes of the blackout, the investigation team looked back through the progression of sequential events, actions and inactions to identify the cause(s) of each event. The idea of "cause" is here linked not just to what happened or why it happened, but more specifically to the entities whose duties and responsibilities were to anticipate and prepare to deal with the things that could go wrong. Four major causes, or groups of causes, are identified (see box on page 18).

Although the causes discussed below produced the failures and events of August 14, they did not leap into being that day. Instead, as the following chapters explain, they reflect long-standing institutional failures and weaknesses that need to be understood and corrected in order to maintain reliability.

Linking Causes to Specific Weaknesses

Seven violations of NERC standards, as identified by NERC,[2] and other conclusions reached by NERC and the bi-national investigation team are aligned below with the specific causes of the blackout. There is an additional category of conclusions beyond the four principal causes—the failure to act, when it was the result of preceding conditions. For instance, FE did not respond to the loss of its transmission lines because it did not have sufficient information or insight to reveal the need for action. Note: NERC's list of violations has been revised and extended since publication of the Interim Report. Two violations (numbers 4 and 6, as cited in the Interim Report) were dropped, and three new violations have been identified in this report (5, 6, and 7, as numbered here). NERC continues to study the record and may identify additional violations.[3]

Group 1: FirstEnergy and ECAR failed to assess and understand the inadequacies of FE's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria and remedial measures.

- FE did not monitor and manage reactive reserves for various contingency conditions as required by NERC Policy 2, Section B, Requirement 2.
- NERC Policy 2, Section A, requires a 30-minute period of time to re-adjust the system to prepare to withstand the next contingency.

Causes of the Blackout's Initiation

The Ohio phase of the August 14, 2003, blackout was caused by deficiencies in specific practices, equipment, and human decisions by various organizations that affected conditions and outcomes that afternoon—for example, insufficient reactive power was an issue in the blackout, but it was not a cause in itself. Rather, deficiencies in corporate policies, lack of adherence to industry policies, and inadequate management of reactive power and voltage caused the blackout, rather than the lack of reactive power. There are four groups of causes for the blackout:

Group 1: FirstEnergy and ECAR failed to assess and understand the inadequacies of FE's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria. *(Note: This cause was not identified in the Task Force's Interim Report. It is based on analysis completed by the investigative team after the publication of the Interim Report.)*

As detailed in Chapter 4:

A) FE failed to conduct rigorous long-term planning studies of its system, and neglected to conduct appropriate multiple contingency or extreme condition assessments. (See pages 37-39 and 41-43.)

B) FE did not conduct sufficient voltage analyses for its Ohio control area and used operational voltage criteria that did not reflect actual voltage stability conditions and needs. (See pages 31-37.)

C) ECAR (FE's reliability council) did not conduct an independent review or analysis of FE's voltage criteria and operating needs, thereby allowing FE to use inadequate practices without correction. (See page 39.)

D) Some of NERC's planning and operational requirements and standards were sufficiently ambiguous that FE could interpret them to include practices that were inadequate for reliable system operation. (See pages 31-33.)

Group 2: Inadequate situational awareness at FirstEnergy. FE did not recognize or understand the deteriorating condition of its system.

As discussed in Chapter 5:

A) FE failed to ensure the security of its transmission system after significant unforeseen contingencies because it did not use an effective contingency analysis capability on a routine basis. (See pages 49-50 and 64.)

B) FE lacked procedures to ensure that its operators were continually aware of the functional state of their critical monitoring tools. (See pages 51-53, 56.)

C) FE control center computer support staff and operations staff did not have effective internal communications procedures. (See pages 54, 56, and 65-67.)

D) FE lacked procedures to test effectively the functional state of its monitoring tools after repairs were made. (See page 54.)

E) FE did not have additional or back-up monitoring tools to understand or visualize the status of their transmission system to facilitate its operators' understanding of transmission system conditions after the failure of their primary monitoring/alarming systems. (See pages 53, 56, and 65.)

Group 3: FE failed to manage adequately tree growth in its transmission rights-of-way.

This failure was the common cause of the outage of three FE 345-kV transmission lines and one 138-kV line. (See pages 57-64.)

Group 4: Failure of the interconnected grid's reliability organizations to provide effective real-time diagnostic support.

As discussed in Chapter 5:

A) MISO did not have real-time data from Dayton Power and Light's Stuart-Atlanta 345-kV line incorporated into its state estimator (a system monitoring tool). This precluded

(continued on page 19)

Causes of the Blackout's Initiation (Continued)

MISO from becoming aware of FE's system problems earlier and providing diagnostic assistance or direction to FE. (See pages 49-50.)

B) MISO's reliability coordinators were using non-real-time data to support real-time "flowgate" monitoring. This prevented MISO from detecting an N-1 security violation in FE's system and from assisting FE in necessary relief actions. (See pages 48 and 63.)

C) MISO lacked an effective way to identify the location and significance of transmission line breaker operations reported by their Energy Management System (EMS). Such information would have enabled MISO operators to become aware earlier of important line outages. (See page 48.)

D) PJM and MISO lacked joint procedures or guidelines on when and how to coordinate a security limit violation observed by one of them in the other's area due to a contingency near their common boundary. (See pages 62-63 and 65-66.)

In the chapters that follow, sections that relate to particular causes are denoted with the following symbols:

Cause 1 Inadequate System Understanding

Cause 2 Inadequate Situational Awareness

Cause 3 Inadequate Tree Trimming

Cause 4 Inadequate RC Diagnostic Support

- NERC is lacking a well-defined control area (CA) audit process that addresses all CA responsibilities. Control area audits have generally not been conducted with sufficient regularity and have not included a comprehensive audit of the control area's compliance with all NERC and Regional Council requirements. Compliance with audit results is not mandatory.
- ECAR did not conduct adequate review or analyses of FE's voltage criteria, reactive power management practices, and operating needs.
- FE does not have an adequate automatic undervoltage load-shedding program in the Cleveland-Akron area.

Group 2: Inadequate situational awareness at FirstEnergy. FE did not recognize or understand the deteriorating condition of its system.

Violations (Identified by NERC):

- **Violation 7:** FE's operational monitoring equipment was not adequate to alert FE's operators regarding important deviations in operating conditions and the need for corrective action as required by NERC Policy 4, Section A, Requirement 5.
- **Violation 3:** FE's state estimation and contingency analysis tools were not used to assess system conditions, violating NERC Operating Policy 5, Section C, Requirement 3, and Policy 4, Section A, Requirement 5.

Other Problems:

- FE personnel did not ensure that their Real-Time Contingency Analysis (RTCA) was a functional and effective EMS application as required by NERC Policy 2, Section A, Requirement 1.
- FE's operational monitoring equipment was not adequate to provide a means for its operators to evaluate the effects of the loss of significant transmission or generation facilities as required by NERC Policy 4, Section A, Requirement 4.
- FE's operations personnel were not provided sufficient operations information and analysis tools as required by NERC Policy 5, Section C, Requirement 3.
- FE's operations personnel were not adequately trained to maintain reliable operation under emergency conditions as required by NERC Policy 8, Section 1.
- NERC Policy 4 has no detailed requirements for: (a) monitoring and functional testing of critical EMS and supervisory control and data acquisition (SCADA) systems, and (b) contingency analysis.
- NERC Policy 6 includes a requirement to plan for loss of the primary control center, but lacks specific provisions concerning what must be addressed in the plan.
- NERC system operator certification tests for basic operational and policy knowledge.

Significant additional training is needed to qualify an individual to perform system operation and management functions.

Group 3: FE failed to manage adequately tree growth in its transmission rights-of-way. This failure was the common cause of the outage of three FE 345-kV transmission lines and affected several 138-kV lines.

- FE failed to maintain equipment ratings through a vegetation management program. A vegetation management program is necessary to fulfill NERC Policy 2, Section A, Requirement 1 (Control areas shall develop, maintain, and implement formal policies and procedures to provide for transmission security . . . including equipment ratings.)
- Vegetation management requirements are not defined in NERC Standards and Policies.

Group 4: Failure of the interconnected grid's reliability organizations to provide effective diagnostic support.

Violations (Identified by NERC):

- **Violation 4**: MISO did not notify other reliability coordinators of potential system problems as required by NERC Policy 9, Section C, Requirement 2.
- **Violation 5**: MISO was using non-real-time data to support real-time operations, in violation of NERC Policy 9, Appendix D, Section A, Criteria 5.2.
- **Violation 6**: PJM and MISO as reliability coordinators lacked procedures or guidelines between their respective organizations regarding the coordination of actions to address an operating security limit violation observed by one of them in the other's area due to a contingency near their common boundary, as required by Policy 9, Appendix C. **Note**: Policy 9 lacks specifics on what constitutes coordinated procedures and training.

Other Problems:

- MISO did not have adequate monitoring capability to fulfill its reliability coordinator responsibilities as required by NERC Policy 9, Appendix D, Section A.
- Although MISO is the reliability coordinator for FE, on August 14 FE was not a signatory to the MISO Transmission Owners Agreement and was not under the MISO tariff, so MISO did not have the necessary authority as FE's Reliability Coordinator as required by NERC Policy 9, Section B, Requirement 2.
- Although lacking authority under a signed agreement, MISO as reliability coordinator nevertheless should have issued directives to FE to return system operation to a safe and reliable level as required by NERC Policy 9, Section B, Requirement 2, before the cascading outages occurred.
- American Electric Power (AEP) and PJM attempted to use the transmission loading relief (TLR) process to address transmission power flows without recognizing that a TLR would not solve the problem.
- NERC Policy 9 does not contain a requirement for reliability coordinators equivalent to the NERC Policy 2 statement that monitoring equipment is to be used in a manner that would bring to the reliability coordinator's attention any important deviations in operating conditions.
- NERC Policy 9 lacks criteria for determining the critical facilities lists in each reliability coordinator area.
- NERC Policy 9 lacks specifics on coordinated procedures and training for reliability coordinators regarding "operating to the most conservative limit" in situations when operating conditions are not fully understood.

Failures to act by FirstEnergy or others to solve the growing problem, due to the other causes.

Violations (Identified by NERC):

- **Violation 1:** Following the outage of the Chamberlin-Harding 345-kV line, FE operating personnel did not take the necessary action to return the system to a safe operating state as required by NERC Policy 2, Section A, Standard 1.
- **Violation 2:** FE operations personnel did not adequately communicate its emergency operating conditions to neighboring systems as required by NERC Policy 5, Section A.

Other Problems:

- FE operations personnel did not promptly take action as required by NERC Policy 5, General

Criteria, to relieve the abnormal conditions resulting from the outage of the Harding-Chamberlin 345-kV line.

- FE operations personnel did not implement measures to return system operation to within security limits in the prescribed time frame of NERC Policy 2, Section A, Standard 2, following the outage of the Harding-Chamberlin 345-kV line.
- FE operations personnel did not exercise the authority to alleviate the operating security limit violation as required by NERC Policy 5, Section C, Requirement 2.
- FE did not exercise a load reduction program to relieve the critical system operating conditions as required by NERC Policy 2, Section A, Requirement 1.2.
- FE did not demonstrate the application of effective emergency operating procedures as required by NERC Policy 6, Section B, Emergency Operations Criteria.
- FE operations personnel did not demonstrate that FE has an effective manual load shedding program designed to address voltage decays that result in uncontrolled failure of components of the interconnection as required by NERC Policy 5, General Criteria.
- NERC Policy 5 lacks specifics for Control Areas on procedures for coordinating with other systems and training regarding "operating to the most conservative limit" in situations when operating conditions are not fully understood.

Institutional Issues

As indicated above, the investigation team identified a number of institutional issues with respect to NERC's reliability standards. Many of the institutional problems arise not because NERC is an inadequate or ineffective organization, but rather because it has no structural independence from the industry it represents and has no authority to develop strong reliability standards and to enforce compliance with those standards. While many in the industry and at NERC support such measures, legislative action by the U.S. Congress is needed to make this happen.

These institutional issues can be summed up generally:

1. Although NERC's provisions address many of the factors and practices which contributed to the blackout, some of the policies or guidelines are inexact, non-specific, or lacking in detail, allowing divergent interpretations among reliability councils, control areas, and reliability coordinators. NERC standards are minimum requirements that may be made more stringent if appropriate by regional or subregional bodies, but the regions have varied in their willingness to implement exacting reliability standards.
2. NERC and the industry's reliability community were aware of the lack of specificity and detail in some standards, including definitions of Operating Security Limits, definition of planned outages, and delegation of Reliability Coordinator functions to control areas, but they moved slowly to address these problems effectively.
3. Some standards relating to the blackout's causes lack specificity and measurable compliance criteria, including those pertaining to operator training, back-up control facilities, procedures to operate when part or all of the EMS fails, emergency procedure training, system restoration plans, reactive reserve requirements, line ratings, and vegetation management.
4. The NERC compliance program and region-based auditing process has not been comprehensive or aggressive enough to assess the capability of all control areas to direct the operation of their portions of the bulk power system. The effectiveness and thoroughness of regional councils' efforts to audit for compliance with reliability requirements have varied significantly from region to region. Equally important, absent mandatory compliance and penalty authority, there is no requirement that an entity found to be deficient in an audit must remedy the deficiency.
5. NERC standards are frequently administrative and technical rather than results-oriented.
6. A recently-adopted NERC process for development of standards is lengthy and not yet fully understood or applied by many industry participants. Whether this process can be adapted to support an expedited development of clear and auditable standards for key topics remains to be seen.

7. NERC has not had an effective process to ensure that recommendations made in various reports and disturbance analyses are tracked for accountability. On their own initiative, some regional councils have developed effective tracking procedures for their geographic areas.

Control areas and reliability coordinators operate the grid every day under guidelines, policies, and requirements established by the industry's reliability community under NERC's coordination. If those policies are strong, clear, and unambiguous, then everyone will plan and operate the system at a high level of performance and reliability will be high. But if those policies are ambiguous and do not make entities' roles and responsibilities clear and certain, they allow companies to perform at varying levels and system reliability is likely to be compromised.

Given that NERC has been a voluntary organization that makes decisions based on member votes, if NERC's standards have been unclear, non-specific, lacking in scope, or insufficiently strict, that reflects at least as much on the industry community that drafts and votes on the standards as it does on NERC. Similarly, NERC's ability to obtain compliance with its requirements through its audit process has been limited by the extent to which the industry has been willing to support the audit program.

Endnotes

[1] *Webster's II New Riverside University Dictionary*, Riverside Publishing Co., 1984.

[2] A NERC team looked at whether and how violations of NERC's reliability requirements may have occurred in the events leading up to the blackout. They also looked at whether deficiencies in the requirements, practices and procedures of NERC and the regional reliability organizations may have contributed to the blackout. They found seven specific violations of NERC operating policies (although some are qualified by a lack of specificity in the NERC requirements).

The Standards, Procedures and Compliance Investigation Team reviewed the NERC Policies for violations, building on work and going beyond work done by the Root Cause Analysis Team. Based on that review the Standards team identified a number of violations related to policies 2, 4, 5, and 9.

Violation 1: Following the outage of the Chamberlin-Harding 345-kV line, FE did not take the necessary actions to return the system to a safe operating state within 30 minutes. (While Policy 5 on Emergency Operations does not address the issue of "operating to the most conservative limit" when coordinating with other systems and operating conditions are not understood, other NERC policies do address this matter: Policy 2, Section A, Standard 1, on basic reliability for single contingencies; Policy 2, Section A, Standard 2, to return a system to within operating security limits within 30 minutes; Policy 2, Section A, Requirement 1, for formal policies and procedures to provide for transmission security; Policy 5, General Criteria, to relieve any abnormal conditions that jeopardize reliable operation; Policy 5, Section C, Requirement 1, to relieve security limit violations; and Policy 5, Section 2, Requirement 2, which gives system operators responsibility and authority to alleviate operating security limit violations using timely and appropriate actions.)

Violation 2: FE did not notify other systems of an impending system emergency. (Policy 5, Section A, Requirement 1, directs a system to inform other systems if it is burdening others, reducing system reliability, or if its lack of single contingency coverage could threaten Interconnection reliability. Policy 5, Section A, Criteria, has similar provisions.)

Violation 3: FE's state estimation/contingency analysis tools were not used to assess the system conditions. (This is addressed in Operating Policy 5, Section C, Requirement 3, concerning assessment of Operating Security Limit violations, and Policy 4, Section A, Requirement 5, which addresses using monitoring equipment to inform the system operator of important conditions and the potential need for corrective action.)

Violation 4: MISO did not notify other reliability coordinators of potential problems. (Policy 9, Section C, Requirement 2, directing the reliability coordinator to alert all control areas and reliability coordinators of a potential transmission problem.)

Violation 5: MISO was using non-real-time data to support real-time operations. (Policy 9, Appendix D, Section A, Criteria For Reliability Coordinators 5.2, regarding adequate facilities to perform their responsibilities, including detailed monitoring capability to identify potential security violations.)

Violation 6: PJM and MISO as Reliability Coordinators lacked procedures or guidelines between themselves on when and how to coordinate an operating security limit violation observed by one of them in the other's area due to a contingency near their common boundary (Policy 9, Appendix 9C, Emergency Procedures). **Note**: Since Policy 9 lacks specifics on coordinated procedures and training, it was not possible for the bi-national team to identify the exact violation that occurred.

Violation 7: The monitoring equipment provided to FE operators was not sufficient to bring the operators' attention to the deviation on the system. (Policy 4, Section A, System Monitoring Requirements regarding resource availability and the use of monitoring equipment to alert operators to the need for corrective action.)

[3] NERC has not yet completed its review of planning standards and violations.

10. Recommendations to Prevent or Minimize the Scope of Future Blackouts

Introduction

As reported in previous chapters, the blackout on August 14, 2003, was preventable. It had several direct causes and contributing factors, including:

- Failure to maintain adequate reactive power support
- Failure to ensure operation within secure limits
- Inadequate vegetation management
- Inadequate operator training
- Failure to identify emergency conditions and communicate that status to neighboring systems
- Inadequate regional-scale visibility over the bulk power system.

Further, as discussed in Chapter 7, after each major blackout in North America since 1965, an expert team of investigators has probed the causes of the blackout, written detailed technical reports, and issued lists of recommendations to prevent or minimize the scope of future blackouts. Yet several of the causes of the August 14 blackout are strikingly similar to those of the earlier blackouts. Clearly, efforts to implement earlier recommendations have not been adequate.[1] Accordingly, the recommendations presented below emphasize comprehensiveness, monitoring, training, and enforcement of reliability standards when necessary to ensure compliance.

It is useful to think of the recommendations presented below in terms of four broad themes:

1. Government bodies in the U.S. and Canada, regulators, the North American electricity industry, and related organizations should commit themselves to making adherence to high reliability standards paramount in the planning, design, and operation of North America's vast bulk power systems. Market mechanisms should be used where possible, but in circumstances where conflicts between reliability and commercial objectives cannot be reconciled, they must be resolved in favor of high reliability.[2]

2. Regulators and consumers should recognize that reliability is not free, and that maintaining it requires ongoing investments and operational expenditures by many parties. Regulated companies will not make such outlays without assurances from regulators that the costs will be recoverable through approved electric rates, and unregulated companies will not make such outlays unless they believe their actions will be profitable.[3]

3. Recommendations have no value unless they are implemented. Accordingly, the Task Force emphasizes strongly that North American governments and industry should commit themselves to working together to put into effect the suite of improvements mapped out below. Success in this area will require particular attention to the mechanisms proposed for performance monitoring, accountability of senior management, and enforcement of compliance with standards.

4. The bulk power systems are among the most critical elements of our economic and social infrastructure. Although the August 14 blackout was not caused by malicious acts, a number of security-related actions are needed to enhance reliability.

Over the past decade or more, electricity demand has increased and the North American interconnections have become more densely woven and heavily loaded, over more hours of the day and year. In many geographic areas, the number of single or multiple contingencies that could create serious problems has increased. Operating the grids at higher loadings means greater stress on equipment and a smaller range of options and a shorter period of time for dealing with unexpected problems. The system operator's job has become more challenging, leading to the need for more sophisticated grid management tools and more demanding operator training programs and certification requirements.

The recommendations below focus on changes of many kinds that are needed to ensure reliability, for both the summer of 2004 and for the years to follow. Making these changes will require higher and broader awareness of the importance of reliability, and some of them may require substantial new investments. However, the cost of *not* making these changes, i.e., the cost of chronic large-scale blackouts, would be far higher than the cost of addressing the problem. Estimates of the cost of the August 14 blackout range between $4 and $10 billion (U.S.).[4]

The need for additional attention to reliability is not necessarily at odds with increasing competition and the improved economic efficiency it brings to bulk power markets. Reliability and economic efficiency can be compatible, but this outcome requires more than reliance on the laws of physics and the principles of economics. It requires sustained, focused efforts by regulators, policy makers, and industry leaders to strengthen and maintain the institutions and rules needed to protect both of these important goals. Regulators must ensure that competition does not erode incentives to comply with reliability requirements, and that reliability requirements do not serve as a smokescreen for noncompetitive practices.

The metric for gauging achievement of this goal—making the changes needed to maintain a high level of reliability for the next decade or longer—will be the degree of compliance obtained with the recommendations presented below. The single most important step in the United States is for the U.S. Congress to enact the reliability provisions in pending energy bills (H.R. 6 and S. 2095). If that can be done, many of the actions recommended below could be accomplished readily in the course of implementing the legislation.

Some commenters asserted that the Interim Report did not analyze all factors they believe may have contributed to the August 14 blackout. Implementation of the recommendations presented below will address all remaining issues, through the ongoing work of government bodies and agencies in the U.S. and Canada, the electricity industry, and the non-governmental institutions responsible for the maintenance of electric reliability in North America.

Recommendations

Forty-six numbered recommendations are presented below, grouped into four substantive areas. Some recommendations concern subjects that were addressed in some detail by commenters on the Interim Report or participants in the Task Force's two technical conferences. In such cases, the commenters are listed in the Endnotes section of this chapter. Citation in the endnotes does not necessarily mean that the commenter supports the position expressed in the recommendation. A "table of contents" overview of the recommendations is provided in the text box on pages 141-142.

Group I. Institutional Issues Related to Reliability

1. Make reliability standards mandatory and enforceable, with penalties for noncompliance.[5]

Appropriate branches of government in the United States and Canada should take action as required to make reliability standards mandatory and enforceable, and to provide appropriate penalties for noncompliance.

A. Action by the U.S. Congress

The U.S. Congress should enact reliability legislation no less stringent than the provisions now included in the pending comprehensive energy bills, H.R. 6 and S. 2095. Specifically, these provisions would require that:

- Reliability standards are to be mandatory and enforceable, with penalties for noncompliance.
- Reliability standards should be developed by an independent, international electric reliability organization (ERO) with fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organizational structure. (See text box on NERC and an ERO below.)

Overview of Task Force Recommendations: Titles Only

Group I. Institutional Issues Related to Reliability

1. Make reliability standards mandatory and enforceable, with penalties for noncompliance.
2. Develop a regulator-approved funding mechanism for NERC and the regional reliability councils, to ensure their independence from the parties they oversee.
3. Strengthen the institutional framework for reliability management in North America.
4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.
5. Track implementation of recommended actions to improve reliability.
6. FERC should not approve the operation of new RTOs or ISOs until they have met minimum functional requirements.
7. Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.
8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.
9. Integrate a "reliability impact" consideration into the regulatory decision-making process.
10. Establish an independent source of reliability performance information.
11. Establish requirements for collection and reporting of data needed for post-blackout analyses.
12. Commission an independent study of the relationships among industry restructuring, competition, and reliability.
13. DOE should expand its research programs on reliability-related tools and technologies.
14. Establish a standing framework for the conduct of future blackout and disturbance investigations.

Group II. Support and Strengthen NERC's Actions of February 10, 2004

15. Correct the direct causes of the August 14, 2003 blackout.
16. Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.
17. Strengthen the NERC Compliance Enforcement Program.
18. Support and strengthen NERC's Reliability Readiness Audit Program.
19. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff.
20. Establish clear definitions for *normal, alert* and *emergency* operational system conditions. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition.
21. Make more effective and wider use of system protection measures.
22. Evaluate and adopt better real-time tools for operators and reliability coordinators.
23. Strengthen reactive power and voltage control practices in all NERC regions.
24. Improve quality of system modeling data and data exchange practices.
25. NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.
26. Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate.
27. Develop enforceable standards for transmission line ratings.
28. Require use of time-synchronized data recorders.
29. Evaluate and disseminate lessons learned during system restoration.
30. Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.
31. Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit. Streamline the TLR process.

(continued on page 142)

Overview of Task Force Recommendations: Titles Only (Continued)

Group III. Physical and Cyber Security of North American Bulk Power Systems

32. Implement NERC IT standards.
33. Develop and deploy IT management procedures.
34. Develop corporate-level IT security governance and strategies.
35. Implement controls to manage system health, network monitoring, and incident management.
36. Initiate U.S.-Canada risk management study.
37. Improve IT forensic and diagnostic capabilities.
38. Assess IT risk and vulnerability at scheduled intervals.
39. Develop capability to detect wireless and remote wireline intrusion and surveillance.
40. Control access to operationally sensitive equipment.
41. NERC should provide guidance on employee background checks.
42. Confirm NERC ES-ISAC as the central point for sharing security information and analysis.
43. Establish clear authority for physical and cyber security.
44. Develop procedures to prevent or mitigate inappropriate disclosure of information.

Group IV. Canadian Nuclear Power Sector

45. The Task Force recommends that the Canadian Nuclear Safety Commission request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.
46. The Task Force recommends that the Canadian Nuclear Safety Commission purchase and install backup generation equipment.

- Reliability standards should allow, where appropriate, flexibility to accommodate regional differences, including more stringent reliability requirements in some areas, but regional deviations should not be allowed to lead to lower reliability expectations or performance.
- An ERO-proposed standard or modification to a standard should take effect within the United States upon approval by the Federal Energy Regulatory Commission (FERC).
- FERC should remand to the ERO for further consideration a proposed reliability standard or a modification to a reliability standard that it disapproves of in whole or in part, with explanation for its concerns and rationale.

B. Action by FERC

In the absence of such reliability legislation, FERC should review its statutory authorities under existing law, and to the maximum extent permitted by those authorities, act to enhance reliability by making compliance with reliability standards enforceable in the United States. In doing so, FERC should consult with state regulators, NERC, and the regional reliability councils to determine whether certain enforcement practices now in use in some parts of the U.S. and Canada might be applied more broadly. For example, in the Western U.S. and Canada, many members of the Western Electricity Coordinating Council (WECC) include clauses in contracts for the purchase of wholesale power that require the parties to comply with reliability standards. In the areas of the U.S. and Canada covered by the Northeast Power Coordinating Council (NPCC), parties found not to be in compliance with NERC and NPCC reliability requirements are subject to escalating degrees of scrutiny by their peers and the public. Both of these approaches have had positive effects. FERC should examine other approaches as well, and work with state regulatory authorities to ensure

NERC and the ERO

If the proposed U.S. reliability legislation passes, the North American Electric Reliability Council (NERC) may undertake various organizational changes and seek recognition as the electric reliability organization (ERO) called for in H.R. 6 and S. 2095. For simplicity of presentation, the many forward-looking references below to “NERC” are intended to apply to the ERO if the legislation is passed, and to NERC if the legislation is not passed.

that any other appropriate actions to make reliability standards enforceable are taken.

Action by FERC under its existing authorities would not lessen the need for enactment of reliability legislation by the Congress. Many U.S. parties that should be required by law to comply with reliability requirements are not subject to the Commission's full authorities under the Federal Power Act.

C. Action by Appropriate Authorities in Canada

The interconnected nature of the transmission grid requires that reliability standards be identical or compatible on both sides of the Canadian/U.S. border. Several provincial governments in Canada have already demonstrated support for mandatory and enforceable reliability standards and have either passed legislation or have taken steps to put in place the necessary framework for implementing such standards in Canada. The federal and provincial governments should work together and with appropriate U.S. authorities to complete a framework to ensure that identical or compatible standards apply in both countries, and that means are in place to enforce them in all interconnected jurisdictions.

D. Joint Actions by U.S. and Canadian Governments

International coordination mechanisms should be developed between the governments in Canada and the United States to provide for government oversight of NERC or the ERO, and approval and enforcement of reliability standards.

E. Memoranda of Understanding between U.S. or Canadian Government Agencies and NERC

Government agencies in both countries should decide (individually) whether to develop a memorandum of understanding (MOU) with NERC that would define the agency's working relationship with NERC, government oversight of NERC activities if appropriate, and the reliability responsibilities of the signatories.

2. Develop a regulator-approved mechanism for funding NERC and the regional reliability councils, to ensure their independence from the parties they oversee.[6]

U.S. and Canadian regulatory authorities should work with NERC, the regional councils, and the industry to develop and implement a new funding mechanism for NERC and the regional councils based on a surcharge in transmission rates. The purpose would be to ensure that NERC and the councils are appropriately funded to meet their changing responsibilities without dependence on the parties that they oversee. Note: Implementation of this recommendation should be coordinated with the review called for in Recommendation 3 concerning the future role of the regional councils.

NERC's current $13 million/year budget is funded as part of the dues that transmission owners, generators, and other market participants pay to the ten regional reliability councils, which then fund NERC. This arrangement makes NERC subject to the influence of the reliability councils, which are in turn subject to the influence of their control areas and other members. It also compromises the independence of both NERC and the councils in relation to the entities whose actions they oversee, and makes it difficult for them to act forcefully and objectively to maintain the reliability of the North American bulk power system. Funding NERC and the councils through a transmission rate surcharge administered and disbursed under regulatory supervision would enable the organizations to be more independent of the industry, with little impact on electric bills. The dues that companies pay to the regional councils are passed through to electricity customers today, so the net impacts on customer bills from shifting to a rate surcharge would be minimal.

Implementation of the recommendations presented in this report will involve a substantial increase in NERC's functions and responsibilities, and require an increase in NERC's annual budget. The additional costs, however, would be small in comparison to the cost of a single major blackout.

3. Strengthen the institutional framework for reliability management in North America.[7]

FERC, DOE and appropriate authorities in Canada should work with the states, NERC, and the industry, to evaluate and develop appropriate modifications to the existing institutional framework for reliability management. In particular, the affected government agencies should:

A. Commission an independent review by qualified experts in organizational design and management to address issues concerning how best to structure an international reliability organization for the long term.

B. Based in part on the results of that review, develop metrics for gauging the adequacy of NERC's performance, and specify the functions of the NERC Board of Trustees and the procedure for selecting the members of the Board.

C. Examine and clarify the future role of the regional reliability councils, with particular attention to their mandate, scope, structure, responsibilities, and resource requirements.

D. Examine NERC's proposed Functional Model and set minimum requirements under which NERC would certify applicants' qualifications to perform critical functions.

E. Request NERC and the regional councils to suspend designation of any new control areas (or sub-control areas) until the minimum requirements in section D (above) have been established, unless an applicant shows that such designation would significantly enhance reliability.

F. Determine ways to enhance reliability operations in the United States through simplified organizational boundaries and resolution of seams issues.

A and B. Reshaping NERC

The far-reaching organizational changes in the North American electricity industry over the past decade have already induced major changes in the nature of NERC as an organization. However, the process of change at NERC is far from complete. Important additional changes are needed such as the shift to enforceable standards, development of an effective monitoring capability, and funding that is not dependent on the industry. These changes will strengthen NERC as an organization. In turn, to properly serve overarching public policy concerns, this strengthening of NERC's capabilities will have to be balanced with increased government oversight, more specific metrics for gauging NERC's performance as an organization, and greater transparency concerning the functions of its senior management team (including its Board of Trustees) and the procedures by which those individuals are selected. The affected government agencies should jointly commission an independent review of these and related issues to aid them in making their respective decisions.

C. The Role of the Regional Reliability Councils

North America's regional reliability councils have evolved into a disparate group of organizations with varying responsibilities, expertise, roles, sizes and resources. Some have grown from a reliability council into an ISO or RTO (ERCOT and SPP), some span less than a single state (FRCC and ERCOT) while others cover many states and provinces and cross national boundaries (NPCC and WECC). Several cross reliability coordinator boundaries. It is time to evaluate the appropriate size and scope of a regional council, the specific tasks that it should perform, and the appropriate level of resources, expertise, and independence that a regional reliability council needs to perform those tasks effectively. This evaluation should also address whether the councils as currently constituted are appropriate to meet future reliability needs.

D. NERC's Functional Model

The transition to competition in wholesale power markets has been accompanied by increasing diversity in the kinds of entities that need to be in compliance with reliability standards. Rather than resist or attempt to influence this evolution, NERC's response—through the Functional Model—has been to seek a means of enabling reliability to be maintained under virtually any institutional framework. The Functional Model identifies sixteen basic functions associated with operating the bulk electric systems and maintaining reliability, and the capabilities that an organization must have in order to perform a given function. (See Functional Model text box below.)

NERC acknowledges that maintaining reliability in some frameworks may be more difficult or more expensive than in others, but it stresses that as long as some responsible party addresses each function and the rules are followed, reliability will be preserved. By implication, the pros and cons of alternative institutional frameworks in a given region—which may affect aspects of electric industry operations other than reliability—are matters for government agencies to address, not NERC.

One of the major purposes of the Functional Model is to create a vehicle through which NERC will be able to identify an entity responsible for performing each function in every part of the three North American interconnections. NERC considers four of the sixteen functions to be especially critical for reliability. For these functions, NERC intends, upon application by an entity, to review the entity's capabilities, and if appropriate, certify that the entity has the qualifications to perform that function within the specified geographic area. For the other twelve functions, NERC proposes to "register" entities as responsible for a given function in a given area, upon application.

All sixteen functions are presently being performed to varying degrees by one entity or another today in all areas of North America. Frequently an entity performs a combination of functions, but there is great variety from one region to another in how the functions are bundled and carried out. Whether all of the parties who are presently performing the four critical functions would meet NERC's requirements for certification is not known, but the proposed process provides a means of identifying any weaknesses that need to be rectified.

At present, after protracted debate, the Functional Model appears to have gained widespread but cautious support from the diverse factions across the industry, while the regulators have not taken a position. In some parts of North America, such as the Northeast, large regional organizations will probably be certified to perform all four of the critical functions for their respective areas. In other areas, capabilities may remain less aggregated, and the institutional structure may remain more complex.

Sixteen Functions in NERC's Functional Model

- **Operating Reliability**
- **Planning Reliability**
- **Balancing** (generation and demand)
- **Interchange**
- Transmission service
- Transmission ownership
- Transmission operations
- Transmission planning
- Resource planning
- Distribution
- Generator ownership
- Generator operations
- Load serving
- Purchasing and selling
- Standards development
- Compliance monitoring

NERC regards the four functions shown above in bold as especially critical to reliability. Accordingly, it proposes to certify applicants that can demonstrate that they have the capabilities required to perform those functions. The Operating Reliability authority would correspond to today's reliability coordinator, and the Balancing authority to today's control area operator.

Working with NERC and the industry, FERC and authorities in Canada should review the Functional Model to ensure that operating hierarchies and entities will facilitate, rather than hinder, efficient reliability operations. At a minimum, the review should identify ways to eliminate inappropriate commercial incentives to retain control area status that do not support reliability objectives; address operational problems associated with institutional fragmentation; and set minimum requirements with respect to the capabilities requiring NERC certification, concerning subjects such as:

1. Fully operational backup control rooms.
2. System-wide (or wider) electronic map boards or functional equivalents, with data feeds that are independent of the area's main energy management system (EMS).
3. Real-time tools that are to be available to the operator, with backups. (See Recommendation 22 below for more detail concerning minimum requirements and guidelines for real-time operating tools.)
4. SCADA and EMS requirements, including backup capabilities.
5. Training programs for all personnel who have access to a control room or supervisory responsibilities for control room operations. (See Recommendation 19 for more detail on the Task Force's views regarding training and certification requirements.)
6. Certification requirements for control room managers and staff.

E. Designation of New Control Areas

Significant changes in the minimum functional requirements for control areas (or balancing authorities, in the context of the Functional Model) may result from the review called for above. Accordingly, the Task Force recommends that regulatory authorities should request NERC and the regional councils not to certify any new control areas (or sub-control areas) until the appropriate regulatory bodies have approved the minimum functional requirements for such bodies, unless an applicant shows that such designation would significantly enhance reliability.

F. Boundary and Seam Issues and Minimum Functional Requirements

Some observers believe that some U.S. regions have too many control areas performing one or more of the four critical reliability functions. In many cases, these entities exist to retain commercial advantages associated with some of these functions. The resulting institutional fragmentation and decentralization of control leads to a higher number of operating contacts and seams, complex coordination requirements, misalignment of control areas with other electrical boundaries and/or operating hierarchies, inconsistent practices and tools, and increased compliance monitoring requirements. These consequences hamper the efficiency and reliability of grid operations.

As shown above (text box on page 14), MISO, as reliability coordinator for its region, is responsible for dealing with 37 control areas, whereas PJM now spans 9 control areas, ISO-New England has 2, and the New York ISO, Ontario's IMO, Texas' ERCOT, and Québec's Trans-Energie are themselves the control area operators for their respective large areas. Moreover, it is not clear that small control areas are financially able to provide the facilities and services needed to perform control area functions at the level needed to maintain reliability. This concern applies also to the four types of entities that NERC proposes to certify under the Functional Model (i.e., Reliability Authority, Planning Authority, Balancing Authority, and Interchange Authority).

For the long term, the regulatory agencies should continue to seek ways to ensure that the regional operational frameworks that emerge through the implementation of the Functional Model promote reliable operations. Any operational framework will represent some combination of tradeoffs, but reliability is a critically important public policy objective and should be a primary design criterion.

4. Clarify that prudent expenditures and investments for bulk system reliability (including investments in new technologies) will be recoverable through transmission rates.[8]

FERC and appropriate authorities in Canada should clarify that prudent expenditures and investments by regulated companies to maintain or improve bulk system reliability will be recoverable through transmission rates.

In the U.S., FERC and DOE should work with state regulators to identify and resolve issues related to the recovery of reliability costs and investments through retail rates. Appropriate authorities in Canada should determine whether similar efforts are warranted.

Companies will not make the expenditures and investments required to maintain or improve the reliability of the bulk power system without credible assurances that they will be able to recover their costs.

5. Track implementation of recommended actions to improve reliability.[9]

In the requirements issued on February 10, 2004, NERC announced that it and the regional councils would establish a program for documenting completion of recommendations resulting from the August 14 blackout and other historical outages, as well as NERC and regional reports on violations of reliability standards, results of compliance audits, and lessons learned from system disturbances. The regions are to report on a quarterly basis to NERC.

In addition, NERC intends to initiate by January 1, 2005 a reliability performance monitoring function that will evaluate and report on trends in bulk electric system reliability performance.

The Task Force supports these actions strongly. However, many of the Task Force's recommendations pertain to government bodies as well as NERC. Accordingly:

A. Relevant agencies in the U.S. and Canada should cooperate to establish mechanisms for tracking and reporting to the public on implementation actions in their respective areas of responsibility.

B. NERC should draw on the above-mentioned quarterly reports from its regional councils to prepare annual reports to FERC, appropriate authorities in Canada, and the public on the status of the industry's compliance with recommendations and important trends in electric system reliability performance.

The August 14 blackout shared a number of contributing factors with prior large-scale blackouts, confirming that the lessons and recommendations from earlier blackouts had not been adequately implemented, at least in some geographic areas. Accordingly, parallel and coordinated efforts are needed by the relevant government agencies and NERC to track the implementation of recommendations by governments and the electricity industry. WECC and NPCC have already established programs that could serve as models for tracking implementation of recommendations.

6. FERC should not approve the operation of a new RTO or ISO until the applicant has met the minimum functional requirements for reliability coordinators.

The events of August 14 confirmed that MISO did not yet have all of the functional capabilities required to fulfill its responsibilities as reliability coordinator for the large area within its footprint. FERC should not authorize a new RTO or ISO to become operational until the RTO or ISO has verified that all critical reliability capabilities will be functional upon commencement of RTO or ISO operations.

7. Require any entity operating as part of the bulk power system to be a member of a regional reliability council if it operates within the council's footprint.[10]

The Task Force recommends that FERC and appropriate authorities in Canada be empowered through legislation, if necessary, to require all entities that operate as part of the bulk electric system to certify that they are members of the regional reliability council for all NERC regions in which they operate.

This requirement is needed to ensure that all relevant parties are subject to NERC standards, policies, etc., in all NERC regions in which they operate. Action by the Congress or legislative bodies in Canada may be necessary to provide appropriate authority.

8. Shield operators who initiate load shedding pursuant to approved guidelines from liability or retaliation.[11]

Legislative bodies and regulators should: 1) establish that operators (whether organizations or individuals) who initiate load shedding pursuant to operational guidelines are not subject to liability suits; and 2) affirm publicly that actions to shed load pursuant to such guidelines are not indicative of operator failure.

Timely and sufficient action to shed load on August 14 would have prevented the spread of the blackout beyond northern Ohio. NERC has directed all the regional councils in all areas of North America to review the applicability of plans for under-voltage load shedding, and to support the development of such capabilities where they would be beneficial. However, organizations and individual operators may hesitate to initiate such actions in appropriate circumstances without assurances that they will not be subject to liability suits or other forms of retaliation, provided their action is pursuant to previously approved guidelines.

9. Integrate a "reliability impact" consideration into the regulatory decision-making process.[12]

The Task Force recommends that FERC, appropriate authorities in Canada, and state regulators integrate a formal reliability impact consideration into their regulatory decision-making to ensure that their actions or initiatives either improve or at minimum do no harm to reliability.

Regulatory actions can have unintended consequences. For example, in reviewing proposed utility company mergers, FERC's primary focus has been on financial and rate issues, as opposed to the reliability implications of such mergers. To minimize unintended harm to reliability, and aid the improvement of reliability where appropriate, the Task Force recommends that regulators incorporate a formal reliability impact consideration into their decision processes. At the same time, regulators should be watchful for use of alleged reliability impacts as a smokescreen for anti-competitive or discriminatory behavior.

10. Establish an independent source of reliability performance information.[13]

The U.S. Department of Energy's Energy Information Administration (EIA), in coordination with other interested agencies and data sources (FERC, appropriate Canadian government agencies, NERC, RTOs, ISOs, the regional councils, transmission operators, and generators) should establish common definitions and information collection standards. If the necessary resources can be identified, EIA should expand its current activities to include information on reliability performance.

Energy policy makers and a wide range of economic decision makers need objective, factual information about basic trends in reliability performance. EIA and the other organizations cited above should identify information gaps in federal data collections covering reliability performance and physical characteristics. Plans to fill those gaps should be developed, and the associated resource requirements determined. Once those resources have been acquired, EIA should publish information on trends, patterns, costs, etc. related to reliability performance.

11. Establish requirements for collection and reporting of data needed for post-blackout analyses.

FERC and appropriate authorities in Canada should require generators, transmission owners, and other relevant entities to collect and report data that may be needed for analysis of blackouts and other grid-related disturbances.

The investigation team found that some of the data needed to analyze the August 14 blackout fully was not collected at the time of the events, and thus could not be reported. Some of the data that was reported was based on incompatible definitions and formats. As a result, there are aspects of the blackout, particularly concerning the evolution of the cascade, that may never be fully explained. FERC, EIA and appropriate authorities in Canada should consult with NERC, key members of the investigation team, and the industry to identify information gaps, adopt common definitions, and establish filing requirements.

12. Commission an independent study of the relationships among industry restructuring, competition, and reliability.[14]

DOE and Natural Resources Canada should commission an independent study of the relationships among industry restructuring, competition in power markets, and grid reliability, and how those relationships should be managed to best serve the public interest.

Some participants at the public meetings held in Cleveland, New York and Toronto to review the Task Force's Interim Report expressed the view that the restructuring of electricity markets for competition in many jurisdictions has, itself, increased the likelihood of major supply interruptions. Some of these commenters assert that the transmission system is now being used to transmit power over distances and at volumes that were not envisioned when the system was designed, and that this functional shift has created major risks that have not been adequately addressed. Indeed, some commenters believe that restructuring was a major cause of the August 14 blackout.

The Task Force believes that the Interim Report accurately identified the primary causes of the blackout. It also believes that had existing reliability requirements been followed, either the disturbance in northern Ohio that evolved on August 14 into a blackout would not have occurred, or it would have been contained within the FE control area.

Nevertheless, as discussed at the beginning of this chapter, the relationship between competition in power markets and reliability is both important and complex, and careful management and sound rules are required to achieve the public policy goals of reasonable electricity prices and high reliability. At the present stage in the evolution of these markets, it is worthwhile for DOE and Natural Resources Canada (in consultation with FERC and the Canadian Council of Energy Ministers) to commission an independent expert study to provide advice on how to achieve and sustain an appropriate balance in this important area.

Among other things, this study should take into account factors such as:

- Historical and projected load growth
- Location of new generation in relation to old generation and loads
- Zoning and NIMBY[15] constraints on siting of generation and transmission
- Lack of new transmission investment and its causes
- Regional comparisons of impact of wholesale electric competition on reliability performance and on investments in reliability and transmission
- The financial community's preferences and their effects on capital investment patterns
- Federal vs. state jurisdictional concerns
- Impacts of state caps on retail electric rates
- Impacts of limited transmission infrastructure on energy costs, transmission congestion, and reliability

- ◆ Trends in generator fuel and wholesale electricity prices
- ◆ Trends in power flows, line losses, voltage levels, etc.

13. DOE should expand its research programs on reliability-related tools and technologies.[16]

DOE should expand its research agenda, and consult frequently with Congress, FERC, NERC, state regulators, Canadian authorities, universities, and the industry in planning and executing this agenda.

More investment in research is needed to improve grid reliability, with particular attention to improving the capabilities and tools for system monitoring and management. Research on reliability issues and reliability-related technologies has a large public-interest component, and government support is crucial. DOE already leads many research projects in this area, through partnerships with industry and research under way at the national laboratories and universities. DOE's leadership and frequent consultation with many parties are essential to ensure the allocation of scarce research funds to urgent projects, bring the best talent to bear on such projects, and enhance the dissemination and timely application of research results.

Important areas for reliability research include but are not limited to:

- ◆ Development of practical real-time applications for wide-area system monitoring using phasor measurements and other synchronized measuring devices, including post-disturbance applications.
- ◆ Development and use of enhanced techniques for modeling and simulation of contingencies, blackouts, and other grid-related disturbances.
- ◆ Investigation of protection and control alternatives to slow or stop the spread of a cascading power outage, including demand response initiatives to slow or halt voltage collapse.
- ◆ Re-evaluation of generator and customer equipment protection requirements based on voltage and frequency phenomena experienced during the August 14, 2003, cascade.
- ◆ Investigation of protection and control of generating units, including the possibility of multiple steps of over-frequency protection and possible effects on system stability during major disturbances.
- ◆ Development of practical human factors guidelines for power system control centers.
- ◆ Study of obstacles to the economic deployment of demand response capability and distributed generation.
- ◆ Investigation of alternative approaches to monitoring right-of-way vegetation management.
- ◆ Study of air traffic control, the airline industry, and other relevant industries for practices and ideas that could reduce the vulnerability of the electricity industry and its reliability managers to human error.

Cooperative and complementary research and funding between nations and between government and industry efforts should be encouraged.

14. Establish a standing framework for the conduct of future blackout and disturbance investigations.[17]

The U.S., Canadian, and Mexican governments, in consultation with NERC, should establish a standing framework for the investigation of future blackouts, disturbances, or other significant grid-related incidents.

Fortunately, major blackouts are not frequent, which makes it important to study such events carefully to learn as much as possible from the experience. In the weeks immediately after August 14, important lessons were learned pertaining not only to preventing and minimizing future blackouts, but also to the efficient and fruitful investigation of future grid-related events.

Appropriate U.S., Canadian, and Mexican government agencies, in consultation with NERC and other organizations, should prepare an agreement that, among other considerations:

- ◆ Establishes criteria for determining when an investigation should be initiated.
- ◆ Establishes the composition of a task force to provide overall guidance for the inquiry. The task force should be international if the triggering event had international consequences.
- ◆ Provides for coordination with state and provincial governments, NERC and other appropriate entities.

- Designates agencies responsible for issuing directives concerning preservation of records, provision of data within specified periods to a data warehouse facility, conduct of onsite interviews with control room personnel, etc.
- Provides guidance on confidentiality of data.
- Identifies types of expertise likely to be needed on the investigation team.

Group II. Support and Strengthen NERC's Actions of February 10, 2004

On February 10, 2004, after taking the findings of the Task Force's investigation into the August 14, 2003, blackout into account, the NERC Board of Trustees approved a series of actions and strategic and technical initiatives intended to protect the reliability of the North American bulk electric system. (See Appendix D for the full text of the Board's statement of February 10.) Overall, the Task Force supports NERC's actions and initiatives strongly. On some subjects, the Task Force advocates additional measures, as shown in the next 17 recommendations.

15. Correct the direct causes of the August 14, 2003 blackout.[18]

NERC played an important role in the Task Force's blackout investigation, and as a result of the findings of the investigation, NERC issued directives on February 10, 2004 to FirstEnergy, MISO, and PJM to complete a series of remedial actions by June 30, 2004 to correct deficiencies identified as factors contributing to the blackout of August 14, 2003. (For specifics on the actions required by NERC, see Appendix D.)

The Task Force supports and endorses NERC's near-term requirements strongly. It recommends the addition of requirements pertaining to ECAR, and several other additional elements, as described below.

A. Corrective Actions to Be Completed by FirstEnergy by June 30, 2004

The full text of the remedial actions NERC has required that FirstEnergy (FE) complete by June 30 is provided in Appendix D. The Task Force recommends the addition of certain elements to these requirements, as described below.

1. Examination of Other FE Service Areas

The Task Force's investigation found severe reactive power and operations criteria deficiencies in the Cleveland-Akron area.

NERC:

Specified measures required in that area to help ensure the reliability of the FE system and avoid undue risks to neighboring systems. However, the blackout investigation did not examine conditions in FE service areas in other states.

Task Force:

Recommends that NERC require FE to review its entire service territory, in all states, to determine whether similar vulnerabilities exist and require prompt attention. This review should be completed by June 30, 2004, and the results reported to FERC, NERC, and utility regulatory authorities in the affected states.

2. Interim Voltage Criteria

NERC:

Required that FE, consistent with or as part of a study ordered by FERC on December 24, 2003,[19] determine the minimum acceptable location-specific voltages at all 345 kV and 138 kV buses and all generating stations within the FE control area (including merchant plants). Further, FE is to determine the minimum dynamic reactive reserves that must be maintained in local areas to ensure that these minimum voltages are met following contingencies studied in accordance with ECAR Document 1.[20] Criteria and minimum voltage requirements must comply with NERC planning criteria, including Table 1A, Category C3, and Operating Policy 2.[21]

Task Force:

Recommends that NERC appoint a team, joined by representatives from FERC and the Ohio Public Utility Commission, to review and approve all such criteria.

3. FE Actions Based on FERC-Ordered Study

NERC:

Required that when the FERC-ordered study is completed, FE is to adopt the planning and operating criteria determined as a result of that study and update the operating criteria and procedures for its system operators. If the study indicates a need for system reinforcement, FE is to develop a plan for developing such resources as soon as practical and develop operational procedures or other mitigating programs to maintain safe operating conditions until such time that the necessary system reinforcements can be made.

Task Force:

Recommends that a team appointed by NERC and joined by representatives from FERC and the Ohio Public Utility Commission should review and approve this plan.

4. Reactive Resources

NERC:

Required that FE inspect all reactive resources, including generators, and ensure that all are fully operational. FE is also required to verify that all installed capacitors have no blown fuses and that at least 98% of installed capacitors (69 kV and higher) are available for service during the summer of 2004.

Task Force:

Recommends that NERC also require FE to confirm that all non-utility generators in its area have entered into contracts for the sale of generation committing them to producing increased or maximum reactive power when called upon by FE or MISO to do so. Such contracts should ensure that the generator would be compensated for revenue losses associated with a reduction in real power sales in order to increase production of reactive power.

5. Operational Preparedness and Action Plan

NERC:

Required that FE prepare and submit to ECAR an Operational Preparedness and Action Plan to ensure system security and full compliance with NERC and planning and operating criteria, including ECAR Document 1.

Task Force:

Recommends that NERC require copies of this plan to be provided to FERC, DOE, the Ohio Public Utility Commission, and the public utility commissions in other states in which FE operates. The Task Force also recommends that NERC require FE to invite its system operations partners—control areas adjacent to FE, plus MISO, ECAR, and PJM—to participate in the development of the plan and agree to its implementation in all aspects that could affect their respective systems and operations.

6. Emergency Response Resources

NERC:

Required that FE develop a capability to reduce load in the Cleveland-Akron area by 1500 MW within ten minutes of a directive to do so by MISO or the FE system operator. Such a capability may be provided by automatic or manual load shedding, voltage reduction, direct-controlled commercial or residential load management, or any other method or combination of methods capable of achieving the 1500 MW of reduction in ten minutes without adversely affecting other interconnected systems. The amount of required load reduction capability may be modified to an amount shown by the FERC-ordered study to be sufficient for response to severe contingencies *and* if approved by ECAR and NERC.

Task Force:

Recommends that NERC require MISO's approval of any change in the amount of required load reduction capability. It also recommends that NERC require FE's load reduction plan to be shared with the Ohio Public Utilities Commission and that FE should communicate with all communities in the affected areas about the plan and its potential consequences.

7. Emergency Response Plan

NERC:

Required that FE develop an emergency response plan, including arrangements for deploying the load reduction capabilities noted above. The plan is to include criteria for determining the existence of an emergency and identify various possible states of emergency. The plan is to include detailed operating procedures and communication protocols with all the relevant entities including MISO, FE operators, and market participants within the FE area that have an ability to vary generation output or shed load upon orders from FE operators. The plan should include procedures for load restoration after the declaration that the FE system is no longer in an emergency operating state.

Task Force:

Recommends that NERC require FE to offer its system operations partners—i.e., control areas adjacent to FE, plus MISO, ECAR, and PJM—an opportunity to contribute to the development of the plan and agree to its key provisions.

8. Operator Communications

NERC:

Required that FE develop communications procedures for FE operating personnel to use within FE, with MISO and neighboring systems, and others. The procedure and the operating environment within the FE system control center should allow control room staff to focus on reliable system operations and avoid distractions such as calls from customers and others who are not responsible for operation of a portion of the transmission system.

Task Force:

Recommends that NERC require these procedures to be shared with and agreed to by control areas adjacent to FE, plus MISO, ECAR, and PJM, and any other affected system operations partners, and that these procedures be tested in a joint drill.

9. Reliability Monitoring and System Management Tools

NERC:

Required that FE ensure that its state estimator and real-time contingency analysis functions are used to execute reliably full contingency analyses automatically every ten minutes or on demand, and used to notify operators of potential first contingency violations.

Task Force:

Recommends that NERC also require FE to ensure that its information technology support function does not change the effectiveness of reliability monitoring or management tools in any way without the awareness and consent of its system operations staff.

10. GE XA21 System Updates and Transition to New Energy Management System

NERC:

Required that until FE replaces its GE XA21 Energy Management System, FE should implement all current known fixes for the GE XA21 system necessary to ensure reliable and stable operation of critical reliability functions, and particularly to correct the alarm processor failure that occurred on August 14, 2003.

Task Force:

Recommends that NERC require FE to design and test the transition to its planned new energy management system to ensure that the system functions effectively, that the transition is made smoothly, that the system's operators are adequately trained, and that all operating partners are aware of the transition.

11. Emergency Preparedness Training for Operators

NERC:

Required that all reliability coordinators, control areas, and transmission operators provide at least five days of training and drills using realistic simulation of system emergencies for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. The term "realistic simulation" includes a variety of tools and methods that present operating personnel with situations to improve and test diagnostic and decision-making skills in an environment that resembles expected conditions during a particular type of system emergency.

Task Force:

Recommends that to provide effective training before June 30, 2004, NERC should require FE to consider seeking the assistance of another control area or reliability coordinator known to have a quality training program (such as IMO or ISO-New England) to provide the needed training with appropriate FE-specific modifications.

B. Corrective Actions to be Completed by MISO by June 30, 2004

1. Reliability Tools

NERC:

Required that MISO fully implement and test its topology processor to provide its operating personnel a real-time view of the system status for all transmission lines operating and all generating units within its system, and all critical transmission lines and generating units in neighboring systems. Alarms should be provided for operators for all critical transmission line outages and voltage violations. MISO is to establish a means of exchanging outage information with its members and adjacent systems such that the MISO state estimator has accurate and timely information to perform as designed. MISO is to fully implement and test its state estimation and real-time contingency analysis tools to ensure they can operate reliably no less than every ten minutes. MISO is to provide backup capability for all functions critical to reliability.

Task Force:

Recommends that NERC require MISO to ensure that its information technology support staff does not change the effectiveness of reliability monitoring or management tools in any way without the awareness and consent of its system operations staff.

2. Operating Agreements

NERC:

Required that MISO reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive management, voltage scheduling, the deployment and redispatch of real and reactive reserves for emergency response, and the authority to direct actions during system emergencies, including shedding load.

Task Force:

Recommends that NERC require that any problems or concerns related to these operating issues be raised promptly with FERC and MISO's members for resolution.

C. Corrective Actions to be Completed by PJM by June 30, 2004

NERC:

Required that PJM reevaluate and improve its communications protocols and procedures between PJM and its neighboring control areas and reliability coordinators.

Task Force:

Recommends that NERC require definitions and usages of key terms be standardized, and non-essential communications be minimized during disturbances, alerts, or emergencies. NERC should also require PJM, MISO, and their member companies to conduct one or more joint drills using the new communications procedures.

D. Task Force Recommendations for Corrective Actions to be Completed by ECAR by August 14, 2004

1. Modeling and Assessments

Task Force:

Recommends that NERC require ECAR to reevaluate its modeling procedures, assumptions, scenarios and data for seasonal assessments and extreme conditions evaluations. ECAR should consult with an expert team appointed by NERC—joined by representatives from FERC, DOE, interested state commissions, and MISO—to develop better modeling procedures and scenarios, and obtain review of future assessments by the expert team.

2. Verification of Data and Assumptions

Task Force:

Recommends that NERC require ECAR to reexamine and validate all data and model assumptions against current physical asset capabilities and match modeled assets (such as line characteristics and ratings, and generator reactive power output capabilities) to current operating study assessments.

3. Ensure Consistency of Members' Data

Task Force:

Recommends that NERC require ECAR to conduct a data validation and exchange exercise to be sure that its members are using accurate, consistent, and current physical asset characteristics and capabilities for both long-term and seasonal assessments and operating studies.

E. Task Force Recommendation for Corrective Actions to be Completed by Other Parties by June 30, 2004

Task Force:

Recommends that NERC require each North American reliability coordinator, reliability council, control area, and transmission company not directly addressed above to review the actions required above and determine whether it has adequate system facilities, operational procedures, tools, and training to ensure reliable operations for the summer of 2004. If any entity finds that improvements are needed, it should immediately undertake the needed improvements, and coordinate them with its neighbors and partners as necessary.

The Task Force also recommends that FERC and government agencies in Canada require all entities under their jurisdiction who are users of GE/Harris XA21 Energy Management Systems to consult the vendor and ensure that appropriate actions have been taken to avert any recurrence of the malfunction that occurred on FE's system on August 14.

16. Establish enforceable standards for maintenance of electrical clearances in right-of-way areas.[22]

On February 10, the NERC Board directed the NERC Compliance Program and the regional councils to initiate a joint program for reporting all bulk electric system transmission line trips resulting from vegetation contact. Based on the results of these filings, NERC is to consider the development of minimum line clearance standards to ensure reliability.

The Task Force believes that more aggressive action is warranted. NERC should work with FERC, appropriate authorities in Canada, state regulatory agencies, the Institute of Electrical and Electronic Engineers (IEEE), utility arborists, and other experts from the US and Canada to develop clear, unambiguous standards pertaining to maintenance of safe clearances of transmission lines from obstructions in the lines' right-of-way areas, and to develop a mechanism to verify compliance with the standards and impose penalties for noncompliance.

Ineffective vegetation management was a major cause of the August 14, 2003, blackout and it was also a causal factor in other large-scale North American outages such as those that occurred in the summer of 1996 in the western United States. Maintaining transmission line rights-of-way, including maintaining safe clearances of energized lines from vegetation, man-made structures, bird nests, etc., requires substantial expenditures in many areas of North America. However, such maintenance is a critical investment for ensuring a reliable electric system. For a review of current issues pertaining to utility vegetation management programs, see *Utility Vegetation Management Final Report*, March 2004.[23]

NERC does not presently have standards for right-of-way maintenance. However, it has standards requiring that line ratings be set to maintain safe clearances from all obstructions. Line rating standards should be reviewed to ensure that they are sufficiently clear and explicit. In the United States, National Electrical Safety Code (NESC) rules specify safety clearances required for overhead conductors from grounded objects and other types of obstructions, but those rules are subject to broad interpretation. Several states have adopted their own electrical safety codes and similar codes apply in Canada and its provinces. A mechanism is needed to verify compliance with these requirements and to penalize noncompliance.

A. Enforceable Standards

NERC should work with FERC, government agencies in Canada, state regulatory agencies, the Institute of Electrical and Electronic Engineers (IEEE), utility arborists, and other experts from the U.S. and Canada to develop clear, unambiguous standards pertaining to maintenance of safe clearances of transmission lines from obstructions in the lines' right-of-way areas, and procedures to verify compliance with the standards. States, provinces, and local governments should remain free to set more specific or higher standards as they deem necessary for their respective areas.

B. Right-of-Way Management Plan

NERC should require each bulk electric transmission operator to publish annually a proposed right-of-way management plan on its public website, and a report on its right-of-way management activities for the previous year. The management plan should include the planned frequency of actions such as right-of-way trimming, herbicide treatment, and inspections, and the report should give the dates when the rights-of-way in a given district were last inspected and corrective actions taken.

C. Requirement to Report Outages Due to Ground Faults in Right-of-Way Areas

Beginning with an effective date of March 31, 2004, NERC should require each transmission owner/operator to submit quarterly reports of all ground-fault line trips, including their causes, on lines of 115 kV and higher in its footprint to the regional councils. Failure to report such trips should lead to an appropriate penalty. Each regional council should assemble a detailed annual report on ground fault line trips and their causes in its area to FERC, NERC, DOE, appropriate authorities in Canada, and state regulators no later than March 31 for the preceding year, with the first annual report to be filed in March 2005 for calendar year 2004.

D. Transmission-Related Vegetation Management Expenses, if Prudently Incurred, Should be Recoverable through Electric Rates

The level of activity in vegetation management programs in many utilities and states has fluctuated widely from year to year, due in part to inconsistent funding and varying management support. Utility managers and regulators should recognize the importance of effective vegetation management to transmission system reliability, and that changes in vegetation management may be needed in response to weather, insect infestations, and other factors. Transmission vegetation management programs should be consistently funded and proactively managed to maintain and improve system reliability.

17. Strengthen the NERC Compliance Enforcement Program.

On February 10, 2004, the NERC Board of Trustees approved directives to the regional reliability councils that will significantly strengthen NERC's existing Compliance Enforcement Program. The Task Force supports these directives strongly, and recommends certain additional actions, as described below.[24]

A. Reporting of Violations

NERC:

Requires each regional council to report to the NERC Compliance Enforcement Program within one month of occurrence all "significant violations" of NERC operating policies and planning standards and regional standards, whether verified or still under investigation by the regional council. (A "significant violation" is one that could directly reduce the integrity of the interconnected power systems or otherwise cause unfavorable risk to the interconnected power systems.) In addition, each regional council is to report quarterly to NERC, in a format prescribed by NERC, all violations of NERC and regional reliability standards.

Task Force:

Recommends that NERC require the regional councils' quarterly reports and reports on significant violations be filed as public documents with FERC and appropriate authorities in Canada, at the same time that they are sent to NERC.

B. Enforcement Action by NERC Board

NERC:

After being presented with the results of the investigation of a significant violation, the Board is to require an offending organization to correct the violation within a specified time. If the Board determines that the organization is non-responsive and continues to cause a risk to the reliability of the interconnected power systems, the Board will seek to remedy the violation by requesting assistance from appropriate regulatory authorities in the United States and Canada.

Task Force:

Recommends that NERC inform the federal and state or provincial authorities of both countries of the final results of all enforcement proceedings, and make the results of such proceedings public.

C. Violations in August 14, 2003 Blackout

NERC:

The Compliance and Standards investigation team will issue a final report in March or April of 2004 of violations of NERC and regional standards that occurred on August 14. (Seven violations are noted in this report (pages 19-20), but additional violations may be identified by NERC.) Within three months of the issuance of the report, NERC is to develop recommendations to improve the compliance process.

Task Force:

Recommends that NERC make its recommendations available to appropriate U.S. federal and state authorities, to appropriate authorities in Canada, and to the public.

D. Compliance Audits

NERC:

Established plans for two types of audits, compliance audits and readiness audits. Compliance audits would determine whether the subject entity is in documented compliance with NERC standards, policies, etc. Readiness audits focus on whether the entity is functionally capable of meeting the terms of its reliability responsibilities. Under the terms approved by NERC's Board, the readiness audits to be completed by June 30, 2004, will be conducted using existing NERC rules, policies, standards, and NERC compliance templates. Requirements for control areas will be based on the existing NERC Control Area Certification Procedure, and updated as new criteria are approved.

Task Force:

Supports the NERC effort to verify that all entities are compliant with reliability standards. Effective compliance and auditing will require that the NERC standards be improved rapidly to make them clear, unambiguous, measurable, and consistent with the Functional Model.

E. Audit Standards and Composition of Audit Teams

NERC:

Under the terms approved by the Board, the regional councils are to have primary responsibility for conducting the compliance audits, under the oversight and direct participation of staff from the NERC Compliance Enforcement Program. FERC and other relevant regulatory agencies will be invited to participate in the audits, subject to the same confidentiality conditions as the other team members.

Task Force:

Recommends that each team should have some members who are electric reliability experts from outside the region in which the audit is occurring. Also, some team members should be from outside the electricity industry, i.e., individuals with experience in systems engineering and management, such as persons from the nuclear power industry, the U.S. Navy, the aerospace industry, air traffic control, or other relevant industries or government agencies. To improve the objectivity and consistency of investigation and performance, NERC-organized teams should conduct these compliance audits, using NERC criteria (with regional variations if more stringent), as opposed to the regional councils using regionally developed criteria.

F. Public Release of Compliance Audit Reports

Task Force:

Recommends that NERC require all compliance audit reports to be publicly posted, excluding portions pertaining to physical and cyber security according to predetermined criteria. Such reports should draw clear distinctions between serious and minor violations of reliability standards or related requirements.

18. Support and strengthen NERC's Reliability Readiness Audit Program.[25]

On February 10, 2004, the NERC Board of Trustees approved the establishment of a NERC program for periodic reviews of the reliability readiness of all reliability coordinators and control areas. The Task Force strongly supports this action, and recommends certain additional measures, as described below.

A. Readiness Audits

NERC:

In its directives of February 10, 2004, NERC indicated that it and the regional councils would jointly establish a program to audit the reliability readiness of all reliability coordinators and control areas within three years and continuing thereafter on a three-year cycle. Twenty audits of high-priority areas will be completed by June 30, 2004, with particular attention to deficiencies identified in the investigation of the August 14 blackout.

Task Force:

Recommends that the remainder of the first round of audits be completed within two years, as compared to NERC's plan for three years.

B. Public Release of Readiness Audit Reports

Task Force:

Recommends that NERC require all readiness audit reports to be publicly posted, excluding portions pertaining to physical and cyber security. Reports should also be sent directly to DOE, FERC, and relevant authorities in Canada and state commissions. Such reports should draw clear distinctions between serious and minor violations of reliability standards or related requirements.

19. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff.[26]

In its requirements of February 10, 2004, NERC directed that all reliability coordinators, control areas, and transmission operators are to provide at least five days per year of training and drills in system emergencies, using realistic simulations, for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. Five days of system emergency training and drills are to be completed by June 30, 2004.

The Task Force supports these near-term requirements strongly. For the long term, the Task Force recommends that:

A. NERC should require training for the planning staff at control areas and reliability coordinators concerning power system characteristics

and load, VAr, and voltage limits, to enable them to develop rules for operating staff to follow.

B. NERC should require control areas and reliability coordinators to train grid operators, IT support personnel, and their supervisors to recognize and respond to abnormal automation system activity.

C. NERC should commission an advisory report by an independent panel to address a wide range of issues concerning reliability training programs and certification requirements.

The Task Force investigation team found that some reliability coordinators and control area operators had not received adequate training in recognizing and responding to system emergencies. Most notable was the lack of realistic simulations and drills to train and verify the capabilities of operating personnel. Such simulations are essential if operators and other staff are to be able to respond adequately to emergencies. This training deficiency contributed to the lack of situational awareness and failure to declare an emergency on August 14 while operator intervention was still possible (before events began to occur at a speed beyond human control).

Control rooms must remain functional under a wide range of possible conditions. Any person with access to a control room should be trained so that he or she understands the basic functions of the control room, and his or her role in relation to those of others in the room under any conditions. Information technology (IT) staff, in particular, should have a detailed understanding of the information needs of the system operators under alternative conditions.

The Task Force's cyber investigation team noted in its site visits an increasing reliance by control areas and utilities on automated systems to measure, report on, and change a wide variety of physical processes associated with utility operations.[27] If anything, this trend is likely to intensify in the future. These systems enable the achievement of major operational efficiencies, but their failure could cause or contribute to blackouts, as evidenced by the alarm failures at FirstEnergy and the state estimator deactivation at MISO.

Grid operators should be trained to recognize and respond more efficiently to security and automation problems, reinforced through the use of periodic exercises. Likewise, IT support personnel should be better trained to understand and respond to the requirements of grid operators during security and IT incidents.

NERC's near-term requirements for emergency preparedness training are described above. For the long term, training for system emergencies should be fully integrated into the broader training programs required for all system planners, system operators, their supervisors, and other control room support staff.

Advisory Report by Independent Panel on Industry Training Programs and Certification Requirements

Under the oversight of FERC and appropriate Canadian authorities, the Task Force recommends that NERC commission an independent advisory panel of experts to design and propose minimum training programs and certification procedures for the industry's control room managers and staff. This panel should be comprised of experts from electric industry organizations with outstanding training programs, universities, and other industries that operate large safety or reliability-oriented systems and training programs. (The Institute of Nuclear Power Operations (INPO), for example, provides training and other safety-related services to operators of U.S. nuclear power plants and plants in other countries.) The panel's report should provide guidance on issues such as:

1. Content of programs for new trainees
2. Content of programs for existing operators and other categories of employees
3. Content of continuing education programs and fraction of employee time to be committed to ongoing training
4. Going beyond paper-based, fact-oriented "knowledge" requirements for operators—i.e., confirming that an individual has the ability to cope with unforeseen situations and emergencies
5. In-house training vs. training by independent parties
6. Periodic accreditation of training programs
7. Who should certify trained staff?
8. Criteria to establish grades or levels of operator qualifications from entry level to supervisor or manager, based on education, training, and experience.

The panel's report should be delivered by March 31, 2005. FERC and Canadian authorities, in consultation with NERC and others, should evaluate the report and consider its findings in setting minimum training and certification requirements for control areas and reliability coordinators.

20. Establish clear definitions for *normal, alert* and *emergency* operational system conditions. Clarify roles, responsibilities, and authorities of reliability coordinators and control areas under each condition.[28]

NERC should develop by June 30, 2004 definitions for normal, alert, and emergency system conditions, and clarify reliability coordinator and control area functions, responsibilities, required capabilities, and required authorities under each operational system condition.

System operators need common definitions for normal, alert, and emergency conditions to enable them to act appropriately and predictably as system conditions change. On August 14, the principal entities involved in the blackout did not have a shared understanding of whether the grid was in an emergency condition, nor did they have a common understanding of the functions, responsibilities, capabilities, and authorities of reliability coordinators and control areas under emergency or near-emergency conditions.

NERC:

On February 10, 2004, NERC's Board of Trustees directed NERC's Operating Committee to "clarify reliability coordinator and control area functions, responsibilities, capabilities, and authorities" by June 30, 2004.

Task Force:

Recommends that NERC go further and develop clear definitions of three operating system conditions, along with clear statements of the roles and responsibilities of all participants, to ensure effective and timely actions in critical situations.

Designating three alternative system conditions (normal, alert, and emergency) would help grid managers to avert and deal with emergencies through preventive action. Many difficult situations are avoidable through strict adherence to sound procedures during normal operations. However, unanticipated difficulties short of an emergency still arise, and they must be addressed swiftly and skillfully to prevent them from becoming emergencies. Doing so requires a high level of situational awareness that is difficult to sustain indefinitely, so an intermediate "alert" state is needed, between "normal" and "emergency." In some areas (e.g., NPCC) an "alert" state has already been established.

21. Make more effective and wider use of system protection measures.[29]

In its requirements of February 10, 2004, NERC:

A. Directed all transmission owners to evaluate the settings of zone 3 relays on all transmission lines of 230 kV and higher.

B. Directed all regional councils to evaluate the feasibility and benefits of installing under-voltage load shedding capability in load centers.

C. Called for an evaluation within one year of its planning standard on system protection and control to take into account the lessons from the August 14 blackout.

The Task Force supports these actions strongly, and recommends certain additional measures, as described below.

A. Evaluation of Zone 3 Relays

NERC:

Industry is to review zone 3 relays on lines of 230 kV and higher.

Task Force:

Recommends that NERC broaden the review to include operationally significant 115 kV and 138 kV lines, e.g., lines that are part of monitored flowgates or interfaces. Transmission owners should also look for zone 2 relays set to operate like zone 3s.

B. Evaluation of Applicability of Under-Voltage Load Shedding

NERC:

Required each regional reliability council to evaluate the feasibility and benefits of under-voltage load shedding (UVLS) capability in load centers that could become unstable as a result of insufficient reactive power following credible multiple-contingency events. The regions should complete the initial studies and report the results to NERC within one year. The regions should promote the installation of under-voltage load shedding capabilities within critical areas where beneficial, as determined by the studies to be effective in preventing or containing an uncontrolled cascade of the power system.

Task Force:

Recommends that NERC require the results of the regional studies to be provided to federal and state or provincial regulators at the same time that they are reported to NERC. In addition, NERC should require every entity with a new or existing UVLS program to have a well-documented set of guidelines for operators that specify the conditions and triggers for UVLS use.

C. Evaluation of NERC's Planning Standard III

NERC:

Plans to evaluate Planning Standard III, System Protection and Control, and propose, by March 1, 2005, specific revisions to the criteria to address adequately the issue of slowing or limiting the propagation of a cascading failure, in light of the experience gained on August 14.

Task Force:

Recommends that NERC, as part of the review of Planning Standard III, determine the goals and principles needed to establish an integrated approach to relay protection for generators and transmission lines and the use of under-frequency and under-voltage load shedding (UFLS and UVLS) programs. An integrated approach is needed to ensure that at the local and regional level these interactive components provide an appropriate balance of risks and benefits in terms of protecting specific assets and facilitating overall grid survival. This review should take into account the evidence from August 14 of some unintended consequences of installing Zone 3 relays and using manufacturer-recommended settings for relays protecting generators. It should also include an assessment of the appropriate role and scope of UFLS and UVLS, and the appropriate use of time delays in relays.

Recommends that in this effort NERC should work with industry and government research organizations to assess the applicability of existing and new technology to make the interconnections less susceptible to cascading outages.

22. Evaluate and adopt better real-time tools for operators and reliability coordinators.[30]

NERC's requirements of February 10, 2004, direct its Operating Committee to evaluate within one year the real-time operating tools necessary for reliability operation and reliability coordination, including backup capabilities. The committee's report is to address both minimum acceptable capabilities for critical reliability functions and a guide to best practices.

The Task Force supports these requirements strongly. It recommends that NERC require the committee to:

A. Give particular attention in its report to the development of guidance to control areas and reliability coordinators on the use of automated wide-area situation visualization display systems and the integrity of data used in those systems.

B. Prepare its report in consultation with FERC, appropriate authorities in Canada, DOE, and the regional councils. The report should also inform actions by FERC and Canadian government agencies to establish minimum functional requirements for control area operators and reliability coordinators.

The Task Force also recommends that FERC, DHS, and appropriate authorities in Canada should require annual independent testing and certification of industry EMS and SCADA systems to ensure that they meet the minimum requirements envisioned in Recommendation 3.

A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities. In addition, the failure of FE's control computers and alarm system contributed directly to the lack of situational awareness. Likewise, MISO's incomplete tool set and the failure to supply its state estimator with correct system data on August 14 contributed to the lack of situational awareness. The need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations. Some wide-area tools to aid situational awareness (e.g., real-time phasor measurement systems) have been tested in some regions but are not yet in general use. Improvements in this area will require significant new investments involving existing or emerging technologies.

The investigation of the August 14 blackout revealed that there has been no consistent means across the Eastern Interconnection to provide an understanding of the status of the power grid outside of a control area. Improved visibility of the status of the grid beyond an operator's own area of control would aid the operator in making adjustments in its operations to mitigate potential problems. The expanded view advocated above would also enable facilities to be more proactive in operations and contingency planning.

Annual testing and certification by independent, qualified parties is needed because EMS and SCADA systems are the nerve centers of bulk electric networks. Ensuring that these systems are functioning properly is critical to sound and reliable operation of the networks.

23. Strengthen reactive power and voltage control practices in all NERC regions.[31]

NERC's requirements of February 10, 2004 call for a reevaluation within one year of existing reactive power and voltage control standards and how they are being implemented in the ten NERC regions. However, by June 30, 2004, ECAR is required to review its reactive power and voltage criteria and procedures, verify that its criteria and procedures are being fully implemented in regional and member studies and operations, and report the results to the NERC Board.

The Task Force supports these requirements strongly. It recommends that NERC require the regional analyses to include recommendations for appropriate improvements in operations or facilities, and to be subject to rigorous peer review by experts from within and outside the affected areas.

The Task Force also recommends that FERC and appropriate authorities in Canada require all tariffs or contracts for the sale of generation to include provisions specifying that the generators can be called upon to provide or increase reactive power output if needed for reliability purposes, and that the generators will be paid for any lost revenues associated with a reduction of real power sales attributable to a required increase in the production of reactive power.

Reactive power problems were a significant factor in the August 14 outage, and they were also important elements in several of the earlier outages detailed in Chapter 7.[32] Accordingly, the Task Force agrees that a comprehensive review is needed of North American practices with respect to managing reactive power requirements and maintaining an appropriate balance among alternative types of reactive resources.

Regional Analyses, Peer Reviews, and Follow-Up Actions

The Task Force recommends that each regional reliability council, working with reliability coordinators and the control areas serving major load centers, should conduct a rigorous reliability and adequacy analysis comparable to that outlined in FERC's December 24, 2003, Order[33] to FirstEnergy concerning the Cleveland-Akron area. The Task Force recommends that NERC develop a prioritized list for which areas and loads need this type of analysis and a schedule that ensures that the analysis will be completed for all such load centers by December 31, 2005.

24. Improve quality of system modeling data and data exchange practices.[34]

NERC's requirements of February 10, 2004 direct that within one year the regional councils are to establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. Validated modeling data shall be exchanged on an inter-regional basis as needed for reliable system planning and operation.

The Task Force supports these requirements strongly. The Task Force also recommends that FERC and appropriate authorities in Canada require all generators, regardless of ownership, to collect and submit generator data to NERC, using a regulator-approved template.

The after-the-fact models developed to simulate August 14 conditions and events found that the dynamic modeling assumptions for generator and load power factors in regional planning and operating models were frequently inaccurate. In particular, the assumptions of load power factor were overly optimistic—loads were absorbing much more reactive power than the pre-August 14 models indicated. Another suspected problem concerns modeling of shunt capacitors under depressed voltage conditions.

NERC should work with the regional reliability councils to establish regional power system models that enable the sharing of consistent and validated data among entities in the region. Power flow and transient stability simulations should be periodically benchmarked with actual system events to validate model data. Viable load (including load power factor) and generator testing programs are necessary to improve agreement between power flows and dynamic simulations and the actual system performance.

During the data collection phase of the blackout investigation, when control areas were asked for information pertaining to merchant generation within their area, the requested data was frequently not available because the control area had not recorded the status or output of the generator at a given point in time. Some control area operators also asserted that some of the data that did exist was commercially sensitive or confidential. To correct such problems, the Task Force recommends that FERC and authorities in Canada require all generators, regardless of ownership, to collect and submit generator data, according to a regulator-approved template.

25. NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.[35]

The Task Force recommends that, with support from FERC and appropriate authorities in Canada, NERC should:

A. Re-examine its existing body of standards, guidelines, etc., to identify those that are most important and ensure that all concerns that merit standards are addressed in the plan for standards development.

B. Re-examine the plan to ensure that those that are the most important or the most out-of-date are addressed early in the process.

C. Build on existing provisions and focus on what needs improvement, and incorporate compliance and readiness considerations into the drafting process.

D. Re-examine the Standards Authorization Request process to determine whether, for each standard, a review and modification of an existing standard would be more efficient than development of wholly new text for the standard.

NERC has already begun a long-term, systematic process to reevaluate its standards. It is of the greatest importance, however, that this process not dilute the content of the existing standards, nor conflict with the right of regions or other areas to impose more stringent standards. The state of New York, for example, operates under mandatory and more stringent reliability rules and standards than those required by NERC and NPCC.[36]

Similarly, several commenters on the Interim Report wrote jointly that:

> *NERC standards are the minimum—national standards should always be minimum rather than absolute or "one size fits all" criteria. [Systems for] densely populated areas, like the metropolitan areas of New York, Chicago, or Washington, must be designed and operated in accordance with a higher level of reliability than would be appropriate for sparsely populated parts of the country. It is essential that regional differences in terms of load and population density be recognized in the application of planning and operating criteria. Any move to adopt a national, "one size fits all" formula for all parts of the United States would be disastrous to reliability . . . .*
>
> *A strong transmission system designed and operated in accordance with weakened criteria would be disastrous. Instead, a concerted effort should be undertaken to determine if existing reliability criteria should be strengthened. Such an effort would recognize the geo-electrical magnitude of today's interconnected networks, and the increased complexities deregulation and restructuring have introduced in planning and operating North American power systems. Most important, reliability should be considered a higher priority than commercial use. Only through strong standards and careful engineering can unacceptable power failures like the August 14 blackout be avoided in the future.*[37]

26. Tighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate.[38]

NERC should work with reliability coordinators and control area operators to improve the effectiveness of internal and external communications during alerts, emergencies, or other critical situations, and ensure that all key parties, including state and local officials, receive timely and accurate information. NERC should task the regional councils to work together to develop communications protocols by December 31, 2004, and to assess and report on the adequacy of emergency communications systems within their regions against the protocols by that date.

On August 14, 2003, reliability coordinator and control area communications regarding conditions in northeastern Ohio were in some cases ineffective, unprofessional, and confusing. Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade. Consistent application of effective communications protocols, particularly during alerts and emergencies, is essential to reliability. Standing hotline networks, or a functional equivalent, should be established for use in alerts and emergencies (as opposed to one-on-one phone calls) to ensure that all key parties are able to give and receive timely and accurate information.

27. Develop enforceable standards for transmission line ratings.[39]

NERC should develop clear, unambiguous requirements for the calculation of transmission line ratings (including dynamic ratings), and require that all lines of 115 kV or higher be rerated according to these requirements by June 30, 2005.

As seen on August 14, inadequate vegetation management can lead to the loss of transmission lines that are not overloaded, at least not according to their rated limits. The investigation of the blackout, however, also found that even after allowing for regional or geographic differences, there is still significant variation in how the ratings of existing lines have been calculated. This variation—in terms of assumed ambient temperatures, wind speeds, conductor strength, and the purposes and duration of normal, seasonal, and emergency ratings—makes the ratings themselves unclear, inconsistent, and unreliable across a region or between regions. This situation creates unnecessary and unacceptable uncertainties about the safe carrying capacity of individual lines on the transmission networks. Further, the appropriate use of dynamic line ratings needs to be included in this review because adjusting a line's rating according to changes in ambient conditions may enable the line to carry a larger load while still meeting safety requirements.

28. Require use of time-synchronized data recorders.[40]

In its requirements of February 10, 2004, NERC directed the regional councils to define within one year regional criteria for the application of synchronized recording devices in key power plants and substations.

The Task Force supports the intent of this requirement strongly, but it recommends a broader approach:

A. FERC and appropriate authorities in Canada should require the use of data recorders synchronized by signals from the Global Positioning System (GPS) on all categories of facilities whose data may be needed to investigate future system disturbances, outages, or blackouts.

B. NERC, reliability coordinators, control areas, and transmission owners should determine where high speed power system disturbance recorders are needed on the system, and ensure that they are installed by December 31, 2004.

C. NERC should establish data recording protocols.

D. FERC and appropriate authorities in Canada should ensure that the investments called for in this recommendation will be recoverable through transmission rates.

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. The Task Force's investigators labored over thousands of data items to determine the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly faster and easier if there had been wider use of synchronized data recording devices.

NERC Planning Standard I.F, Disturbance Monitoring, requires the use of recording devices for disturbance analysis. On August 14, time recorders were frequently used but not synchronized to a time standard. Today, at a relatively modest cost, all digital fault recorders, digital event recorders, and power system disturbance recorders can and should be time-stamped at the point of observation using a Global Positioning System (GPS) synchronizing signal. (The GPS signals are synchronized with the atomic clock maintained in Boulder, Colorado by the U.S. National Institute of Standards and Technology.) Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability.

It is also important that data from automation systems be retained at least for some minimum period, so that if necessary it can be archived to enable adequate analysis of events of particular interest.

29. Evaluate and disseminate lessons learned during system restoration.[41]

In the requirements it issued on February 10, 2004, NERC directed its Planning Committee to work with the Operating Committee, NPCC, ECAR, and PJM to evaluate the black start and system restoration performance following the outage of August 14, and to report within one year the results of that evaluation, with recommendations for

improvement. Within six months of the Planning Committee's report, all regional councils are to have reevaluated their plans and procedures to ensure an effective black start and restoration capability within their region.

The Task Force supports these requirements strongly. In addition, the Task Force recommends that NERC should require the Planning Committee's review to include consultation with appropriate stakeholder organizations in all areas that were blacked out on August 14.

The efforts to restore the power system and customer service following the outage were generally effective, considering the massive amount of load lost and the large number of generators and transmission lines that tripped. Fortunately, the restoration was aided by the ability to energize transmission from neighboring systems, thereby speeding the recovery.

Despite the apparent success of the restoration effort, it is important to evaluate the results in more detail to compare them with previous blackout/restoration studies and determine opportunities for improvement. Black start and restoration plans are often developed through study of simulated conditions. Robust testing of live systems is difficult because of the risk of disturbing the system or interrupting customers. The August 14 blackout provides a valuable opportunity to review actual events and experiences to learn how to better prepare for system black start and restoration in the future. That opportunity should not be lost.

30. Clarify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages.[42]

NERC should work with the control areas and reliability coordinators to clarify the criteria for identifying critical facilities whose operational status can affect the reliability of neighboring areas, and to improve mechanisms for sharing information about unplanned outages of such facilities in near real-time.

The lack of accurate, near real-time information about unplanned outages degraded the performance of state estimator and reliability assessment functions on August 14. NERC and the industry must improve the mechanisms for sharing outage information in the operating time horizon (e.g., 15 minutes or less), to ensure the accurate and timely sharing of outage data needed by real-time operating tools such as state estimators, real-time contingency analyzers, and other system monitoring tools.

Further, NERC's present operating policies do not specify adequately criteria for identifying those critical facilities within reliability coordinator and control area footprints whose operating status could affect the reliability of neighboring systems. This leads to uncertainty about which facilities should be monitored by both the reliability coordinator for the region in which the facility is located and by one or more neighboring reliability coordinators.

31. Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit. Streamline the TLR process.[43]

NERC should clarify that the TLR procedure is often too slow for use in situations in which an affected system is already in violation of an Operating Security Limit. NERC should also evaluate experience to date with the TLR procedure and propose by September 1, 2004, ways to make it less cumbersome.

The reviews of control area and reliability coordinator transcripts from August 14 confirm that the TLR process is cumbersome, perhaps unnecessarily so, and not fast and predictable enough for use situations in which an Operating Security Limit is close to or actually being violated. NERC should develop an alternative to TLRs that can be used quickly to address alert and emergency conditions.

Group III. Physical and Cyber Security of North American Bulk Power Systems

32. Implement NERC IT standards.

The Task Force recommends that NERC standards related to physical and cyber security should be understood as being included within the body of standards to be made mandatory and enforceable in Recommendation No. 1. Further:

A. NERC should ensure that the industry has implemented its Urgent Action Standard 1200; finalize, implement, and ensure membership compliance with its Reliability Standard 1300 for Cyber Security and take actions to better communicate and enforce these standards.

B. CAs and RCs should implement existing and emerging NERC standards, develop and implement best practices and policies for IT and

security management, and authenticate and authorize controls that address EMS automation system ownership and boundaries.

Interviews and analyses conducted by the SWG indicate that within some of the companies interviewed there are potential opportunities for cyber system compromise of EMS and their supporting IT infrastructure. Indications of procedural and technical IT management vulnerabilities were observed in some facilities, such as unnecessary software services not denied by default, loosely controlled system access and perimeter control, poor patch and configuration management, and poor system security documentation.

An analysis of the more prevalent policies and standards within the electricity sector revealed that there is existing and expanding guidance on standards within the sector to perform IT and information security management.[44] NERC issued a temporary standard (Urgent Action Standard 1200, Cyber Security) on August 13, 2003, and is developing the formal Reliability Standard 1300 for Cyber Security. Both start the industry down the correct path, but there is a need to communicate and enforce these standards by providing the industry with recommended implementation guidance. Implementation guidance regarding these sector-wide standards is especially important given that implementation procedures may differ among CAs and RCs.

In order to address the finding described above, the Task Force recommends:

- NERC:
  - ➢ Ensure that the industry has implemented its Urgent Action Standard 1200 and determine if the guidance contained therein needs to be strengthened or amended in the ongoing development of its Reliability Standard 1300 for Cyber Security.
  - ➢ Finalize, implement, and ensure membership compliance of its Reliability Standard 1300 for Cyber Security and take actions to better communicate and enforce these standards. These actions should include, but not necessarily be limited to:
    1. The provision of policy, process, and implementation guidance to CAs and RCs; and
    2. The establishment of mechanisms for compliance, audit, and enforcement. This may include recommendations, guidance, or agreements between NERC, CAs and RCs that cover self-certification, self-assessment, and/or third-party audit.
  - ➢ Work with federal, state, and provincial/territorial jurisdictional departments and agencies to regularly update private and public sector standards, policies, and other guidance.
- CAs and RCs:
  - ➢ Implement existing and emerging NERC standards.
  - ➢ Develop and implement best practices and policies for IT and security management drawing from existing NERC and government authorities' best practices.[45] These should include, but not necessarily be limited to:
    1. Policies requiring that automation system products be delivered and installed with unnecessary services deactivated in order to improve "out-of-the-box security."
    2. The creation of centralized system administration authority within each CA and RC to manage access and permissions for automation access (including vendor management backdoors, links to other automation systems, and administrative connections).
  - ➢ Authenticate and authorize controls that address EMS automation system ownership and boundaries, and ensure access is granted only to users who have corresponding job responsibilities.

33. Develop and deploy IT management procedures.

CAs' and RCs' IT and EMS support personnel should develop procedures for the development, testing, configuration, and implementation of technology related to EMS automation systems and also define and communicate information security and performance requirements to vendors on a continuing basis. Vendors should ensure that system upgrades, service packs, and bug fixes are made available to grid operators in a timely manner.

Interviews and analyses conducted by the SWG indicate that, in some instances, there were ill-defined and/or undefined procedures for EMS automation systems software and hardware development, testing, deployment, and backup. In addition, there were specific instances of failures to perform system upgrade, version control, maintenance, rollback, and patch management tasks.

At one CA, these procedural vulnerabilities were compounded by inadequate, out-of-date, or non-existing maintenance contracts with EMS vendors and contractors. This could lead to situations where grid operators could alter EMS components without vendor notification or authorization as well as scenarios in which grid operators are not aware of or choose not to implement vendor-recommended patches and upgrades.

34. Develop corporate-level IT security governance and strategies.

CAs and RCs and other grid-related organizations should have a planned and documented security strategy, governance model, and architecture for EMS automation systems.

Interviews and analysis conducted by the SWG indicate that in some organizations there is evidence of an inadequate security policy, governance model, strategy, or architecture for EMS automation systems. This is especially apparent with legacy EMS automation systems that were originally designed to be stand-alone systems but that are now interconnected with internal (corporate) and external (vendors, Open Access Same Time Information Systems (OASIS), RCs, Internet, etc.) networks. It should be noted that in some of the organizations interviewed this was not the case and in fact they appeared to excel in the areas of security policy, governance, strategy, and architecture.

In order to address the finding described above, the Task Force recommends that CAs, RCs, and other grid-related organizations have a planned and documented security strategy, governance model, and architecture for EMS automation systems covering items such as network design, system design, security devices, access and authentication controls, and integrity management as well as backup, recovery, and contingency mechanisms.

35. Implement controls to manage system health, network monitoring, and incident management.

IT and EMS support personnel should implement technical controls to detect, respond to, and recover from system and network problems. Grid operators, dispatchers, and IT and EMS support personnel should be provided the tools and training to ensure that the health of IT systems is monitored and maintained.

Interviews and analysis conducted by the SWG indicate that in some organizations there was ineffective monitoring and control over EMS-supporting IT infrastructure and overall IT network health. In these cases, both grid operators and IT support personnel did not have situational awareness of the health of the IT systems that provide grid information both globally and locally. This resulted in an inability to detect, assess, respond to, and recover from IT system-related cyber failures (failed hardware/software, malicious code, faulty configurations, etc.).

In order to address the finding described above, the Task Force recommends:

- IT and EMS support personnel implement technical controls to detect, respond to, and recover from system and network problems.
- Grid operators, dispatchers, and IT and EMS support personnel be provided with the tools and training to ensure that:
  - The health of IT systems is monitored and maintained.
  - These systems have the capability to be repaired and restored quickly, with a minimum loss of time and access to global and internal grid information.
  - Contingency and disaster recovery procedures exist and can serve to temporarily substitute for systems and communications failures during times when EMS automation system health is unknown or unreliable.
  - Adequate verbal communication protocols and procedures exist between operators and IT and EMS support personnel so that operators are aware of any IT-related problems that may be affecting their situational awareness of the power grid.

36. Initiate a U.S.-Canada risk management study.

In cooperation with the electricity sector, federal governments should strengthen and expand the scope of the existing risk management initiatives by undertaking a bilateral (Canada-U.S.) study of the vulnerabilities of shared electricity infrastructure and cross border interdependencies. Common threat and vulnerability assessment methodologies should be also developed, based on the work undertaken in the pilot phase of the current joint Canada-U.S. vulnerability assessment initiative, and their use promoted by CAs and RCs. To coincide with these initiatives, the electricity sector, in association with federal governments, should

develop policies and best practices for effective risk management and risk mitigation.

Effective risk management is a key element in assuring the reliability of our critical infrastructures. It is widely recognized that the increased reliance on IT by critical infrastructure sectors, including the energy sector, has increased the vulnerability of these systems to disruption via cyber means. The breadth of the August 14, 2003, power outage illustrates the vulnerabilities and interdependencies inherent in our electricity infrastructure.

Canada and the United States, recognizing the importance of assessing the vulnerabilities of shared energy systems, included a provision to address this issue in the Smart Border Declaration,[46] signed on December 12, 2001. Both countries committed, pursuant to Action Item 21 of the Declaration, to "conduct bi-national threat assessments on trans-border infrastructure and identify necessary protection measures, and initiate assessments for transportation networks and other critical infrastructure." These joint assessments will serve to identify critical vulnerabilities, strengths and weaknesses while promoting the sharing and transfer of knowledge and technology to the energy sector for self-assessment purposes.

A team of Canadian and American technical experts, using methodology developed by the Argonne National Laboratory in Chicago, Illinois, began conducting the pilot phase of this work in January 2004. The work involves a series of joint Canada-U.S. assessments of selected shared critical energy infrastructure along the Canada-U.S. border, including the electrical transmission lines and dams at Niagara Falls - Ontario and New York. The pilot phase will be completed by March 31, 2004.

The findings of the ESWG and SWG suggest that among the companies directly involved in the power outage, vulnerabilities and interdependencies of the electric system were not well understood and thus effective risk management was inadequate. In some cases, risk assessments did not exist or were inadequate to support risk management and risk mitigation plans.

In order to address these findings, the Task Force recommends:

- In cooperation with the electricity sector, federal governments should strengthen and expand the scope of the existing initiatives described above by undertaking a bilateral (Canada-U.S.) study of the vulnerabilities of shared electricity infrastructure and cross border interdependencies. The study should encompass cyber, physical, and personnel security processes and include mitigation and best practices, identifying areas that would benefit from further standardization.
- Common threat and vulnerability assessment methodologies should be developed, based on the work undertaken in the pilot phase of the current joint Canada-U.S. vulnerability assessment initiative, and their use promoted by CAs and RCs.
- The electricity sector, in association with federal governments, should develop policies and best practices for effective risk management and risk mitigation.

37. Improve IT forensic and diagnostic capabilities.

CAs and RCs should seek to improve internal forensic and diagnostic capabilities, ensure that IT support personnel who support EMS automation systems are familiar with the systems' design and implementation, and make certain that IT support personnel who support EMS automation systems have are trained in using appropriate tools for diagnostic and forensic analysis and remediation.

Interviews and analyses conducted by the SWG indicate that, in some cases, IT support personnel who are responsible for EMS automation systems are unable to perform forensic and diagnostic routines on those systems. This appears to stem from a lack of tools, documentation and technical skills. It should be noted that some of the organizations interviewed excelled in this area but that overall performance was lacking.

In order to address the finding described above, the Task Force recommends:

- CAs and RCs seek to improve internal forensic and diagnostic capabilities as well as strengthen coordination with external EMS vendors and contractors who can assist in servicing EMS automation systems;
- CAs and RCs ensure that IT support personnel who support EMS automation systems are familiar with the systems' design and implementation; and
- CAs and RCs ensure that IT support personnel who support EMS automation systems have access to and are trained in using appropriate

tools for diagnostic and forensic analysis and remediation.

38. Assess IT risk and vulnerability at scheduled intervals.

IT and EMS support personnel should perform regular risk and vulnerability assessment activities for automation systems (including EMS applications and underlying operating systems) to identify weaknesses, high-risk areas, and mitigating actions such as improvements in policy, procedure, and technology.

Interviews and analysis conducted by the SWG indicate that in some instances risk and vulnerability management were not being performed on EMS automation systems and their IT supporting infrastructure. To some CAs, EMS automation systems were considered "black box"[47] technologies; and this categorization removed them from the list of systems identified for risk and vulnerability assessment.

39. Develop capability to detect wireless and remote wireline intrusion and surveillance.

Both the private and public sector should promote the development of the capability of all CAs and RCs to reasonably detect intrusion and surveillance of wireless and remote wireline access points and transmissions. CAs and RCs should also conduct periodic reviews to ensure that their user base is in compliance with existing wireless and remote wireline access rules and policies.

Interviews conducted by the SWG indicate that most of the organizations interviewed had some type of wireless and remote wireline intrusion and surveillance detection protocol as a standard security policy; however, there is a need to improve and strengthen current capabilities regarding wireless and remote wireline intrusion and surveillance detection. The successful detection and monitoring of wireless and remote wireline access points and transmissions are critical to securing grid operations from a cyber security perspective.

There is also evidence that although many of the organizations interviewed had strict policies against allowing wireless network access, periodic reviews to ensure compliance with these policies were not undertaken.

40. Control access to operationally sensitive equipment.

RCs and CAs should implement stringent policies and procedures to control access to sensitive equipment and/or work areas.

Interviews conducted by the SWG indicate that at some CAs and RCs operationally sensitive computer equipment was accessible to non-essential personnel. Although most of these non-essential personnel were escorted through sensitive areas, it was determined that this procedure was not always enforced as a matter of everyday operations.

In order to address the finding described above, the Task Force recommends:

- That RCs and CAs develop policies and procedures to control access to sensitive equipment and/or work areas to ensure that:
  - Access is strictly limited to employees or contractors who utilize said equipment as part of their job responsibilities.
  - Access for other staff who need access to sensitive areas and/or equipment but are not directly involved in their operation (such as cleaning staff and other administrative personnel) is strictly controlled (via escort) and monitored.

41. NERC should provide guidance on employee background checks.

NERC should provide guidance on the implementation of its recommended standards on background checks, and CAs and RCs should review their policies regarding background checks to ensure they are adequate.

Interviews conducted with sector participants revealed instances in which certain company contract personnel did not have to undergo background check(s) as stringent as those performed on regular employees of a CA or RC. NERC Urgent Action Standard Section 1207 Paragraph 2.3 specifies steps to remediate sector weaknesses in this area but there is a need to communicate and enforce this standard by providing the industry with recommended implementation guidance, which may differ among CAs and RCs.

In order to address the finding described above, the Task Force recommends:

- NERC provide guidance on the implementation of its recommended standards on background checks, especially as they relate to the screening of contracted and sub-contracted personnel.

- CAs and RCs review their policies regarding background checks to ensure they are adequate before allowing sub-contractor personnel to access their facilities.

42. Confirm NERC ES-ISAC as the central point for sharing security information and analysis.

The NERC ES-ISAC should be confirmed as the central electricity sector point of contact for security incident reporting and analysis. Policies and protocols for cyber and physical incident reporting should be further developed including a mechanism for monitoring compliance. There also should be uniform standards for the reporting and sharing of physical and cyber security incident information across both the private and public sectors.

There are currently both private and public sector information sharing and analysis initiatives in place to address the reporting of physical and cyber security incidents within the electricity sector. In the private sector, NERC operates an Electricity Sector Information Sharing and Analysis Center (ES-ISAC) specifically to address this issue. On behalf of the U.S. Government, the Department of Homeland Security (DHS) operates the Information Analysis and Infrastructure Protection (IAIP) Directorate to collect, process, and act upon information on possible cyber and physical security threats and vulnerabilities. In Canada, Public Safety and Emergency Preparedness Canada has a 24/7 operations center for the reporting of incidents involving or impacting critical infrastructure. As well, both in Canada and the U.S., incidents of a criminal nature can be reported to law enforcement authorities of jurisdiction.

Despite these private and public physical and cyber security information sharing and analysis initiatives, an analysis of policies and procedures within the electricity sector reveals that reporting of security incidents to internal corporate security, law enforcement, or government agencies was uneven across the sector. The fact that these existing channels for incident reporting—whether security- or electricity systems-related—are currently underutilized is an operating deficiency which could hamper the industry's ability to address future problems in the electricity sector.

Interviews and analysis conducted by the SWG further indicate an absence of coherent and effective mechanisms for the private sector to share information related to critical infrastructure with government. There was also a lack of confidence on the part of private sector infrastructure owners and grid operators that information shared with governments could be protected from disclosure under Canada's Access to Information Act (ATIA) and the U.S. Freedom of Information Act (FOIA). On the U.S. side of the border, however, the imminent implementation of the Critical Infrastructure Information (CII) Act of 2002 should mitigate almost all industry concerns about FOIA disclosure. In Canada, Public Safety and Emergency Preparedness Canada relies on a range of mechanisms to protect the sensitive information related to critical infrastructure that it receives from its private sector stakeholders, including the exemptions for third party information that currently exist in the ATIA and other instruments. At the same time, Public Safety and Emergency Preparedness Canada is reviewing options for stronger protection of CI information, including potential changes in legislation.

In order to address the finding described above, the Task Force recommends:

- Confirmation of the NERC ES-ISAC as the central electricity sector point of contact for security incident reporting and analysis.

- Further development of NERC policies and protocols for cyber and physical incident reporting including a mechanism for monitoring compliance.

- The establishment of uniform standards for the reporting of physical and cyber security incidents to internal corporate security, private sector sector-specific information sharing and analysis bodies (including ISACs), law enforcement, and government agencies.

- The further development of new mechanisms and the promulgation of existing[48] Canadian and U.S. mechanisms to facilitate the sharing of electricity sector threat and vulnerability information across governments as well as between the private sector and governments.

- Federal, state, and provincial/territorial governments work to further develop and promulgate measures and procedures that protect critical, but sensitive, critical infrastructure-related information from disclosure.

43. Establish clear authority for physical and cyber security.

The task force recommends that corporations establish clear authority and ownership for physical and cyber security. This authority should have the ability to influence corporate decision-making and the authority to make physical and cyber security-related decisions.

Interviews and analysis conducted by the SWG indicate that some power entities did not implement best practices when organizing their security staff. It was noted at several entities that the Information System (IS) security staff reported to IT support personnel such as the Chief Information Officer (CIO).

Best practices across the IT industry, including most large automated businesses, indicate that the best way to balance security requirements properly with the IT and operational requirements of a company is to place security at a comparable level within the organizational structure. By allowing the security staff a certain level of autonomy, management can properly balance the associated risks and operational requirements of the facility.

44. Develop procedures to prevent or mitigate inappropriate disclosure of information.

The private and public sectors should jointly develop and implement security procedures and awareness training in order to mitigate or prevent disclosure of information by the practices of open source collection, elicitation, or surveillance.

SWG interviews and intelligence analysis provide no evidence of the use of open source collection, elicitation or surveillance against CAs or RCs leading up to the August 14, 2003, power outage. However, such activities may be used by malicious individuals, groups, or nation states engaged in intelligence collection in order to gain insights or proprietary information on electric power system functions and capabilities. Open source collection is difficult to detect and thus is best countered through careful consideration by industry stakeholders of the extent and nature of publicly-available information. Methods of elicitation and surveillance, by comparison, are more detectable activities and may be addressed through increased awareness and security training. In addition to prevention and detection, it is equally important that suspected or actual incidents of these intelligence collection activities be reported to government authorities.

In order to address the findings described above, the Task Force recommends:

- The private and public sectors jointly develop and implement security procedures and awareness training in order to mitigate disclosure of information not suitable for the public domain and/or removal of previously available information in the public domain (web sites, message boards, industry publications, etc.).
- The private and public sector jointly develop and implement security procedures and awareness training in order to mitigate or prevent disclosure of information by the practices of elicitation.
- The private and public sector jointly develop and implement security procedures and awareness training in order to mitigate, prevent, and detect incidents of surveillance.
- Where no mechanism currently exists, the private and public sector jointly establish a secure reporting chain and protocol for use of the information for suspected and known attempts and incidents of elicitation and surveillance.

Group IV. Canadian Nuclear Power Sector

The U.S. nuclear power plants affected by the August 14 blackout performed as designed. After reviewing the design criteria and the response of the plants, the U.S. members of the Nuclear Working Group had no recommendations relative to the U.S. nuclear power plants.

As discussed in Chapter 8, Canadian nuclear power plants did not trigger the power system outage or contribute to its spread. Rather, they disconnected from the grid as designed. The Canadian members of the Nuclear Working Group have, therefore, no specific recommendations with respect to the design or operation of Canadian nuclear plants that would improve the reliability of the Ontario electricity grid. The Canadian Nuclear Working Group, however, made two recommendations to improve the response to future events involving the loss of off-site power, one concerning backup electrical generation equipment to the CNSC's Emergency Operations Centre and another concerning the use of adjuster rods during future events involving the loss of off-site power. The Task Force accepted these recommendations, which are presented below.

45. The Task Force recommends that the Canadian Nuclear Safety Commission request Ontario Power Generation and Bruce Power to review operating procedures and operator training associated with the use of adjuster rods.

OPG and Bruce Power should review their operating procedures to see whether alternative procedures could be put in place to carry out or reduce the number of system checks required before placing the adjuster rods into automatic mode. This review should include an assessment of any regulatory constraints placed on the use of the adjuster rods, to ensure that risks are being appropriately managed.

Current operating procedures require independent checks of a reactor's systems by the reactor operator and the control room supervisor before the reactor can be put in automatic mode to allow the reactors to operate at 60% power levels. Alternative procedures to allow reactors to run at 60% of power while waiting for the grid to be re-established may reduce other risks to the health and safety of Ontarians that arise from the loss of a key source of electricity. CNSC oversight and approval of any changes to operating procedures would ensure that health and safety, security, or the environment are not compromised. The CNSC would assess the outcome of the proposed review to ensure that health and safety, security, and the environment would not be compromised as a result of any proposed action.

46. The Task Force recommends that the Canadian Nuclear Safety Commission purchase and install backup generation equipment.

In order to ensure that the CNSC's Emergency Operations Center (EOC) is available and fully functional during an emergency situation requiring CNSC response, whether the emergency is nuclear-related or otherwise, and that staff needed to respond to the emergency can be accommodated safely, the CNSC should have backup electrical generation equipment of sufficient capacity to provide power to the EOC, telecommunications and Information Technology (IT) systems and accommodations for the CNSC staff needed to respond to an emergency.

The August 2003 power outage demonstrated that the CNSC's Emergency Operations Center, IT, and communications equipment are vulnerable if there is a loss of electricity to the Ottawa area.

Endnotes

1 In fairness, it must be noted that reliability organizations in some areas have worked diligently to implement recommendations from earlier blackouts. According to the *Initial Report by the New York State Department of Public Service on the August 14, 2003 Blackout*, New York entities implemented all 100 of the recommendations issued after the New York City blackout of 1977.

2 The need for a systematic recommitment to reliability by all affected organizations was supported in various ways by many commenters on the *Interim Report*, including Anthony J. Alexander, FirstEnergy; David Barrie, Hydro One Networks, Inc.; Joseph P. Carson, P.E.; Harrison Clark; F. J. Delea, J.A. Casazza, G.C. Loehr, and R. M. Malizewski, Power Engineers Seeking Truth; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; and Raymond K. Kershaw, International Transmission Company.

3 See supporting comments expressed by Anthony J. Alexander, FirstEnergy; Deepak Divan, SoftSwitching Technologies; Pierre Guimond, Canadian Nuclear Association; Hans Konow, Canadian Electricity Association; Michael Penstone, Hydro One Networks, Inc.; and James K. Robinson, PPL.

4 See "The Economic Impacts of the August 2003 Blackout," Electric Consumers Resource Council (ELCON), February 2, 2004.

5 The need for action to make standards enforceable was supported by many commenters, including David Barrie, Hydro One Networks, Inc.; Carl Burrell, IMO Ontario; David Cook, North American Electric Reliability Council; Deepak Divan, SoftSwitching Technologies; Charles J. Durkin, Northeast Power Coordinating Council; David Goffin, Canadian Chemical Producers' Association; Raymond K. Kershaw, International Transmission Company; Hans Konow, Canadian Electricity Association; Barry Lawson, National Rural Electric Cooperative Association; William J. Museler, New York Independent System Operator; Eric B. Stephens, Ohio Consumers' Counsel; Gordon Van Welie, ISO New England, Inc.; and C. Dortch Wright, on behalf of James McGreevey, Governor of New Jersey.

6 This recommendation was suggested by some members of the Electric System Working Group.

7 The need to evaluate and where appropriate strengthen the institutional framework for reliability management was supported in various respects by many commenters, including Anthony J. Alexander, FirstEnergy Corporation; David Barrie, Hydro One Networks, Inc.; Chris Booth, Experienced Consultants LLC; Carl Burrell, IMO Ontario;Linda Campbell, Florida Reliability Coordinating Council; Linda Church Ciocci, National Hydropower Association; David Cook, NERC; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Charles J. Durkin, Northeast Power Coordinating Council; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Michael W. Golay, Massachusetts Institute of Technology; Leonard S. Hyman, Private Sector Advisors, Inc; Marija Ilic, Carnegie Mellon University; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw,

International Transmission Company; Paul Kleindorfer, University of Pennsylvania; Michael Kormos, PJM Interconnection; Bill Mittelstadt, Bonneville Power Administration; William J. Museler, New York Independent System Operator; James K. Robinson, PPL; Eric B. Stephens, Ohio Consumers' Counsel; John Synesiou, IMS Corporation; Gordon Van Welie, ISO New England; Vickie Van Zandt, Bonneville Power Administration; and C. Dortch Wright, on behalf of James McGreevey, Governor of New Jersey.

[8] Several commenters noted the importance of clarifying that prudently incurred reliability expenses and investments will be recoverable through regulator-approved rates. These commenters include Anthony J. Alexander, FirstEnergy Corporation; Deepak Divan, SoftSwitching Technologies; Stephen Fairfax, MTechnology, Inc.; Michael W. Golay, Massachusetts Institute of Technology; Pierre Guimond, Canadian Nuclear Association; Raymond K. Kershaw, International Transmission Company; Paul R. Kleindorfer, University of Pennsylvania: Hans Konow, Canadian Electricity Association; Barry Lawson, National Rural Electric Cooperative Association; and Michael Penstone, Hydro One Networks, Inc.

[9] The concept of an ongoing NERC process to track the implementation of existing and subsequent recommendations was initated by NERC and broadened by members of the Electric System Working Group. See comments by David Cook, North American Electric Reliability Council.

[10] This recommendation was suggested by NERC and supported by members of the Electric System Working Group.

[11] See comments by Jack Kerr, Dominion Virginia Power, and Margie Phillips, Pennsylvania Services Integration Consortium.

[12] The concept of a "reliability impact consideration" was suggested by NERC and supported by the Electric System Working Group.

[13] The suggestion that EIA should become a source of reliability data and information came from a member of the Electric System Working Group.

[14] Several commenters raised the question of whether there was a linkage between the emergence of competition (or increased wholesale electricity trade) in electricity markets and the August 14 blackout. See comments by Anthony J. Alexander, FirstEnergy Corporation; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Brian O'Keefe, Canadian Union of Public Employees; Les Pereira; and John Wilson.

[15] NIMBY: "Not In My Back Yard."

[16] Several commenters either suggested that government agencies should expand their research in reliability-related topics, or emphasized the need for such R&D more generally. See comments by Deepak Divan, SoftSwitching Technologies; Marija Ilic, Carnegie Mellon University; Hans Konow, Canadian Electricity Association; Stephen Lee, Electric Power Research Institute; James K. Robinson, PPL; John Synesiou, IMS Corporation; and C. Dortch Wright on behalf of Governor James McGreevey of New Jersey.

[17] The concept of a standing framework for grid-related investigations was initiated by members of the Electric System Working Group, after noting that the U.S. National Aeronautics and Space Administration (NASA) had created a similar arrangement after the *Challenger* explosion in 1986. This framework was put to use immediately after the loss of the shuttle *Columbia* in 2003.

[18] This subject was addressed in detail in comments by David Cook, North American Electric Reliability Council; and in part by comments by Anthony J. Alexander, FirstEnergy Corporation; Ajay Garg, Hydro One Networks, Inc.; George Katsuras, IMO Ontario; and Vickie Van Zandt, Bonneville Power Administration.

[19] U.S. Federal Energy Regulatory Commission, 105 FERC ¶ 61,372, December 24, 2003.

[20] See ECAR website, http://www.ecar.org/documents/document%201_6-98.pdf.

[21] See NERC website, http://www.nerc.com/standards/.

[22] The need to ensure better maintenance of required electrical clearances in transmission right of way areas was emphasized by several commenters, including Richard E. Abbott, arborist; Anthony J. Alexander, FirstEnergy Corporation; David Barrie, Hydro One Networks, Inc.; David Cook, North American Electric Reliability Council; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Tadashi Mano, Tokyo Electric Power Company; Eric B. Stephens, Ohio Consumers' Counsel; Vickie Van Zandt, Bonneville Power Administration; and Donald Wightman, Utility Workers Union of America.

[23] *Utility Vegetation Management Final Report*, CN Utility Consulting, LLC, March 2004, commissioned by the U.S. Federal Energy Regulatory Commission to support the investigation of the August 14, 2003 blackout.

[24] The need to strengthen and verify compliance with NERC standards was noted by several commenters. See comments by David Barrie, Hydro One Networks, Inc.; Carl Burrell, IMO Ontario; David Cook, North American Electric Reliability Council; and Eric B. Stephens, Ohio Consumers' Counsel.

[25] The need to verify application of NERC standards via readiness audits—before adverse incidents occur—was noted by several commenters. See comments by David Barrie, Hydro One Networks, Inc.; David Cook, North American Electric Reliability Council; Barry Lawson, National Rural Electric Cooperative Association; Bill Mittelstadt, Bonneville Power Administration; and Eric B. Stephens, Ohio Consumers' Counsel.

[26] The need to improve the training and certification requirements for control room management and staff drew many comments. See comments by David Cook, North American Electric Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Victoria Doumtchenko, MPR Associates; Pat Duran, IMO Ontario; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; George Katsuras, IMO Ontario; Jack Kerr, Dominion Virginia Power; Tim Kucey, National Energy Board, Canada; Stephen Lee, Electric Power Research Institute; Steve Leovy, personal comment; Ed Schwerdt, Northeast Power Coordinating Council; Tapani O. Seppa, The Valley Group, Inc.; Eric B. Stephens, Ohio Consumers' Counsel; Vickie Van Zandt, Bonneville Power Company; Don Watkins, Bonneville Power Administration; and Donald Wightman, Utility Workers Union of America.

[27] This reliance, and the risk of an undue dependence, is often unrecognized in the industry.

[28] Many parties called for clearer statement of the roles, responsibilities, and authorities of control areas and reliability coordinators, particularly in emergency situations. See comments by Anthony J. Alexander, FirstEnergy Corporation; Chris Booth, Experienced Consultants LLC; Michael Calimano, New York ISO; Linda Campbell, Florida Reliability Coordinating Council; David Cook, North American Electric

Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Mark Fidrych, Western Area Power Authority; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Carl Hauser, Washington State University; Stephen Kellat; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw, International Transmission Company; Michael Kormos, PJM Interconnection; William J. Museler, New York Independent System Operator; Tapani O. Seppa, The Valley Group, Inc.; John Synesiou, IMS Corporation; Gordon Van Welie, ISO New England, Inc.; Vickie Van Zandt, Bonneville Power Administration; Kim Warren, IMO Ontario; and Tom Wiedman, Consolidated Edison. Members of the Electric System Working Group initiated the concept of defining an "alert" status, between "normal" and "emergency," and associated roles, responsibilities, and authorities.

29 The need to make better use of system protection measures received substantial comment, including comments by James L. Blasiak, International Transmission Company; David Cook, North American Electric Reliability Council; Charles J. Durkin, Northeast Power Coordinating Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Gurgen and Spartak Hakobyan, personal study; Marija Ilic, Carnegie Mellon University; Shinichi Imai, Tokyo Electric Power Company; Jack Kerr, Dominion Virginia Power; Stephen Lee, Electric Power Research Institute; Ed Schwerdt, Northeast Power Coordinating Council; Robert Stewart, PG&E; Philip Tatro, National Grid Company; Carson Taylor, Bonneville Power Administration; Vickie Van Zandt, Bonneville Power Company; Don Watkins, Bonneville Power Administration; and Tom Wiedman, Consolidated Edison.

30 The subject of developing and adopting better real-time tools for control room operators and reliability coordinators drew many comments, including those by Anthony J. Alexander, FirstEnergy Corporation; Eric Allen, New York ISO; Chris Booth, Experienced Consultants, LLC; Mike Calimano, New York ISO; Claudio Canizares, University of Waterloo (Ontario); David Cook, North American Electric Reliability Council; Deepak Divan, SoftSwitching Technologies Victoria Doumtchenko, MPR Associates; Pat Duran, IMO Ontario; Bill Eggertson, Canadian Association for Renewable Energies; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw, International Transmission Company; Michael Kormos, PJM Interconnection; Tim Kucey, National Energy Board, Canada; Steve Lapp, Lapp Renewables; Stephen Lee, Electric Power Research Institute; Steve Leovy; Tom Levy; Peter Love, Canadian Energy Efficiency Alliance; Frank Macedo, Hydro One Networks, Inc.; Bill Mittelstadt, Bonneville Power Administration; Fiona Oliver, Canadian Energy Efficiency Alliance; Peter Ormund, Mohawk College; Don Ross, Prince Edward Island Wind Co-op Limited; James K. Robinson, PPL; Robert Stewart, PG&E; John Synesiou, IMS Corporation; Gordon Van Welie, ISO New England, Inc.; Vickie Van Zandt, Bonneville Power Administration; Don Watkins, Bonneville Power Administration; Chris Winter, Conservation Council of Ontario; David Zwergel, Midwest ISO. The concept of requiring annual testing and certification of operators' EMS and SCADA systems was initiated by a member of the Electric System Working Group. Also, see comments by John Synesiou, IMS Corporation.

31 The need to strengthen reactive power and voltage control practices was the subject of several comments. See comments by Claudio Canizares, University of Waterloo (Ontario); David Cook, North American Electric Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Stephen Fairfax, MTechnology, Inc.; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Shinichi Imai and Toshihiko Furuya, Tokyo Electric Power Company; Marija Ilic, Carnegie Mellon University; Frank Macedo, Hydro One Networks, Inc.; and Tom Wiedman, Consolidated Edison. Several commenters addressed issues related to the production of reactive power by producers of power for sale in wholesale markets. See comments by Anthony J. Alexander, FirstEnergy Corporation; K.K. Das, PowerGrid Corporation of India, Limited; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Stephen Fairfax, MTechnology, Inc.; and Carson Taylor, Bonneville Power Administration.

32 See pages 107-108.

33 U.S. Federal Energy Regulatory Commission, 105 FERC ¶ 61,372, December 24, 2003.

34 The need to improve the quality of system modeling data and data exchange practices received extensive comment. See comments from Michael Calimano, New York ISO; David Cook, North American Electric Reliability Council; Robert Cummings, North American Electric Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Mark Fidrych, Western Area Power Administration; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw, International Transmission Company; Frank Macedo, Hydro One Networks, Inc.; Vickie Van Zandt, Bonneville Power Administration; Don Watkins, Bonneville Power Administration; and David Zwergel, Midwest ISO.

35 Several commenters addressed the subject of NERC's standards in various respects, including Anthony J. Alexander, FirstEnergy Corporation; Carl Burrell, IMO Ontario; David Cook, North American Electric Reliability Council; F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, Power Engineers Seeking Truth; Charles J. Durkin, Northeast Power Coordinating Council; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Jack Kerr, Dominion Virginia Power; James K. Robinson, PPL; Mayer Sasson, New York State Reliability Council; and Kim Warren, IMO Ontario.

36 See *Initial Report by the New York State Department of Public Service on the August 14, 2003 Blackout* (2004), and comments by Mayer Sasson, New York State Reliability Council.

37 F.J. Delea, J.A. Casazza, G.C. Loehr, and R.M. Malizewski, "The Need for Strong Planning and Operating Criteria to Assure a Reliable Bulk Power Supply System," January 29, 2004.

38 The need to tighten communications protocols and improve communications systems was cited by several commenters. See comments by Anthony J. Alexander, FirstEnergy Corporation; David Barrie, Hydro One Networks, Inc.; Carl Burrell, IMO Ontario; Michael Calimano, New York ISO; David Cook, North American Electric Reliability Council; Mark Fidrych, Western Area Power Administration; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; Jack Kerr, Dominion Virginia Power; William Museler, New York ISO; John Synesiou, IMS Corporation; Vickie Van Zandt, Bonneville Power Administration; Don Watkins, Bonneville Power Administration; Tom Wiedman, Consolidated Edison.

39 See comments by Tapani O. Seppa, The Valley Group, Inc.

40 Several commenters noted the need for more systematic use of time-synchronized data recorders. In particular, see David Cook, North American Electric Reliability Council; Ajay Garg and Michael Penstone, Hydro One Networks, Inc.; and Robert Stewart, PG&E.

[41] The importance of learning from the system restoration experience associated with the August 14 blackout was stressed by Linda Church Ciocci, National Hydropower Association; David Cook, North American Electric Reliability Council; Frank Delea; Bill Eggertson, Canadian Association for Renewable Energies; Stephen Lee, Electric Power Research Institute; and Kim Warren, IMO Ontario.

[42] The need to clarify the criteria for identifying critical facilities and improving dissemination of updated information about unplanned outages was cited by Anthony J. Alexander, FirstEnergy Corporation; and Raymond K. Kershaw, International Transmission Company.

[43] The need to streamline the TLR process and limit the use of it to non-urgent situations was discussed by several commenters, including Anthony J. Alexander, FirstEnergy Corporation; Carl Burrell, IMO Ontario; Jack Kerr, Dominion Virginia Power; Raymond K. Kershaw, International Transmission Company; and Ed Schwerdt, Northeast Power Coordinating Council.

[44] NERC Standards at www.nerc.com (Urgent Action Standard 1200, Cyber Security, Reliability Standard 1300, Cyber Security) and Joint DOE/PCIB standards guidance at www.ea.doe.gov/pdfs/21stepsbooklet.pdf ("21 Steps to Improve Cyber Security of SCADA Networks").

[45] For example: "21 Steps to Improve Cyber Security of SCADA Networks," http://www.ea.doe.gov/pdfs/21stepsbooklet.pdf.

[46] Canadian reference: http://www.dfait-maeci.gc.ca/anti-terrorism/actionplan-en.asp; U.S. reference: http://www.whitehouse.gov/news/releases/2001/12/20011212-6.html.

[47] A "black box" technology is any device, sometimes highly important, whose workings are not understood by or accessible to its user.

[48] DOE Form 417 is an example of an existing, but underutilized, private/public sector information sharing mechanism.

Item 3. Policy 3, Version 0 and Compliance Templates – Doug Hils

Background

The subcommittee will discuss Version 0 at the April 21, 2004 Reliability Standards and Business Practices meeting. Doug Hils will lead the discussion on how Version 0 will affect the previous work of the subcommittee on separating Policy 3 reliability principles and business practices. The subcommittee will continue working on Policy 3 as Version 0 under agenda Item 9a.

Attachment

3a Accelerating the NERC Standards Transition, April 14, 2004

Background

Doug Hils will lead the discussion on the revised Policy 3 Compliance Templates – P3T3 and P3T4. [See ftp://www.nerc.com/pub/sys/all_updl/compliance/cttf/Operating_Templates.pdf]

NERC formed a Compliance Template Task Force to revise the current NERC templates. The group prepared a set of compliance templates that were approved by the NERC Board of Trustees on April 2, 2004. NERC adopted the set of 38 compliance templates for immediate use by NERC's Compliance Enforcement Program. These templates will be used to measure compliance with existing NERC reliability standards. With this action, NERC has implemented another key recommendation in "NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts."

Most of the 38 templates are revised versions of templates that have been used in NERC's Compliance Enforcement Program for several years. They have been edited to more clearly define their measurement and compliance criteria, and to add some new elements based on findings from NERC's investigation into the August 14 outage. For information on the CTTF and the compliance templates see: http://www.nerc.com/%7Efilez/cttf.html

Note on the attachments: The subcommittee reviewed the CTTF's draft P3T3 (3b1) and determined the subcommittee could not support the template. The IS provided a letter to the CTTF (3b2) asking for time to revise the template. The IS drafted two templates for the CTTF (3b3, 3b4) to consider in place of the CTTF's original P3T3. The CTTF revised the IS templates (3b5), and submitted the templates to the BOT for approval.

Attachments

3b1 CTTF Letter with Templates, March 15, 2004

3b2 IS Letter to CTTF, March 19, 2004

3b3 IS Drafted Compliance Template P3T3

3b4 IS Drafted Compliance Template P3T4

3b5 Compliance Templates as submitted to the BOT for approval

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

April 14, 2004

To: Board of Trustees

From: Standards Transition Management Team
Standards Authorization Committee
Operating Committee
Planning Committee
Market Committee
Compliance & Certification Committee
Critical Infrastructure Protection Committee
Regional Managers

Accelerating the NERC Standards Transition

The undersigned NERC committees request that the Board of Trustees endorse the goals stated below for an accelerated transition to NERC reliability standards.

The August 14, 2003 blackout underscores the urgent need for reliability standards that are clear, measurable, and enforceable – now. The Board's approval of compliance templates on April 2 was an immediate response to sharpen the measures used for compliance enforcement. Also, the standing committees are currently balloting proposed revisions that clarify and sharpen three operating policies to address specific lessons from August 14.

On a broader scale, however, NERC faces a potentially protracted transition to enforceable reliability standards developed through the ANSI-accredited process. In the current environment, a multi-year transition is unacceptable. The U.S./Canada Power System Outage Task Force says as much in Recommendation 25 of its April 5 final report on the blackout:

> *NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards.*

The Standards Transition Management Team, with groundswell of support among NERC committees, the regions, and the industry, proposes an accelerated transition project to convert the existing operating policies, planning standards and compliance templates into a baseline Version 0 set of NERC reliability standards for adoption by the Board of Trustees at its February 2005 meeting.

The accelerated standards transition project will:

- Utilize the same reliability requirements documented in the current operating policies, planning standards, and compliance templates.
- Delegate through the Joint Interface Committee any business practices identified in the translation to the North American Energy Standards Board or ISO/RTO Council for adoption as a complementary business practice standard.
- Complete an initial registration of entities performing functions identified in the Functional Model and incorporate those functional designations into the NERC standards.
- Revise the ANSI-accredited standards process to be more streamlined and responsive to reliability issues.
- Upon adoption of the Version 0 standards, retire existing operating policies, planning standards, and compliance templates to work from there forward with a single set of NERC reliability standards.

The undersigned NERC committees:

1. Are moving expeditiously to achieve the goals stated above to allow the Board to adopt the Version 0 reliability standards at its February 2005 Board meeting;
2. Believe that the existing ANSI-accredited standards process can and should be used to adopt the Version 0 reliability standards; and
3. Commit to work with NAESB, the IRC, the Reliability Regions, and the industry to achieve the stated goals.

Linda Campbell
Chairman, Standards
Authorization Committee

Mark Fydrich
Chairman, Operating
Committee

Glenn Ross
Chairman, Planning
Committee

Bob Harbour
Chairman, Compliance &
Certification Committee

Stuart Brindley
Chairman, Critical
Infrastructure Protection
Committee

Mike Grim
Chairman, Market Committee

Ed Schwerdt
Chairman, Regional Managers

Standards Transition
Management Team

cc: SAC, OC, PC, CCC, CIPC, MC, RM, STMT

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

March 15, 2004

TO: NERC ROSTER

Ladies and Gentlemen:

Enclosed for your endorsement is a set of compliance templates from the Compliance Template Task Force (CTTF). The CTTF was created a few weeks ago to assemble this set of templates for presentation to the NERC Board of Trustees on March 31, 2004. This effort is a key element in meeting the requirements of Recommendation 2 of the *NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts*.

If adopted by the board, these compliance templates will be available for immediate use in the NERC Compliance Enforcement Program. These templates will be used in parallel with the readiness audits that are now being conducted in response to Recommendation 3, and form a key part of NERC's strategic initiatives laid out in the NERC Actions document.

The CTTF enlisted the expertise of the Compliance and Certification Managers Committee in assembling these templates. Most of them are edited versions of templates that have been used by the Compliance Enforcement Program for several years. They have been edited to sharpen their measurements and compliance criteria. Some new elements have been added based on findings from NERC's investigation into the August 14 outage.

The CTTF also sought input on the proposed templates from the chairs of the appropriate NERC technical committees and subcommittees. Much of the feedback it received was related to the policy modifications and changes that are in progress or under consideration. The CTTF sought to avoid direct conflicts with these proposed modifications and to put the compliance templates forward with the understanding that they should be approved as submitted and will be modified in the future as new reliability standards are developed and approved.

In a few cases, the CTTF determined that additional technical work was required before an acceptable template could be drafted. For example, reactive power planning and control is one area where measures in the templates would have created policy. No reactive-based templates are included this package. This concern and others will be forwarded to the NERC board, including recommendations for expedited resolution by the technical committees.

Phone 609-452-8060 ■ Fax 609-452-9550 ■ URL www.nerc.com

Another aspect of Recommendation 2 outlines the reporting and response to violations of the compliance templates; as a result, all sanction and penalty sections have been removed. NERC has created a Disclosure Guidelines Task Force, chaired by Tom Berry of the NERC board, to develop draft guidelines for board consideration regarding the confidentiality of compliance information and disclosure of such information to regulatory authorities and the public. That draft guideline is also to be presented to the board by the end of March.

Nothing in this initiative changes NERC's commitment to develop reliability standards using the ANSI-accredited standards development process. As new NERC reliability standards are completed, they will either endorse or supplant these templates. NERC's long-term commitment to the agreement signed with the North American Energy Standards Board and the ISO/RTO Council is also unchanged.

The compliance templates are attached as an Acrobat file. Each template has a preface sheet indicating the origin of the template and, if it is an existing template, the major changes that the CTTF has proposed.

The CTTF would like you to register your endorsement of these compliance templates. Please use the website www.nerc.net/comments and follow the instructions. If you cannot endorse one or more of them, the CTTF asks you to indicate specifically why you cannot do so. We need your response by 5:00 p.m. EST on Friday, March 19.

These responses will be discussed at next week's standing committee meetings and by the CTTF on March 29–30, just before it reports back to the board. In the short time available, it may not be possible to resolve all concerns that might be raised, but the CTTF will ensure that they are presented to the board. Your responses will also be forwarded to Gerry Cauley, NERC's Director of Reliability Standards, to ensure their consideration as new standards are developed.

Thank you for your assistance and support in this important effort.

The Compliance Template Task Force

Walter A. Johnson, Chair	C. Marty Mennes
John A. Anderson	Michael Oliva
Ricky Bittle	Armando J. Perez
Larry E. Bugh	Edward A. Schwerdt
Derek R. Cowbourne	Raymond L. Vice
Joseph R. Hartsoe	David W. Hilt, NERC staff
Sam R. Jones	Martin Sidor, NERC staff

Terms Used in the Templates

Wide-area

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 interconnected reliability limits.

ERRIS

Due to the changes that are occurring across the interconnections, it has become difficult to identify various sectors within each entity. To facilitate the development of the compliance program, the term **ERRIS** (Entities responsible for the reliability of the interconnected system) is being used in some of the compliance templates. An ERRIS can include, but is not limited to control areas, transmission operators, generation operators, balancing authorities etc. In this way, the applicability of each template can be determined by the regional reliability councils to facilitate their particular organizational set up.

P1T1

Control Performance Standard 1 and Control Performance Standard 2

This standard was approved by the NERC OC on July 18, 2002

No changes were made to this template, other than removing the penalties and sanctions

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 and penalties and sanctions applied 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 and penalties and sanctions are applied individually. 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.

P1T2

Disturbance Control Standard

This standard was approved by the NERC OC on July 18, 2002

No changes were made to this template, other than removing the penalties and sanctions

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 and penalties and sanctions applied 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 supports the calculation of DCS is 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 ACEm 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.

P1T4

Maintaining Operating Reserves.

This is a new template.

This template is proposed as a proactive measure to compliment P1T1 and P1T2. Where P1T1 and P1T2 address how well reserves are applied when called upon, P1T4 measures if a Control Area or Reserve Sharing Group carried operating reserves according to Regional Reliability Council reserve requirements.

Principle The frequency of the interconnected BULK ELECTRIC SYSTEM shall be controlled within defined limits through the balancing of electric supply and demand.

Brief Description Maintaining Operating Reserves to meet Regional requirements.

Section Policy 1 Version 2 October 8, 2002
Introduction
Section B Disturbance Control Standard
Section E Automatic Generation Control Standard

Standard

Control Areas, Reserve Sharing Groups and all members of Reserve Sharing Groups shall have access to and/or operate sufficient resources to provide for a level of Operating Reserves to meet the Policy 1 requirements for Operating Reserve (Section A), Control Performance Standard (Section E), and Frequency Response Standard (Section C).

Applicable to

Control Areas, Reserve Sharing Groups and all members of Reserve Sharing Groups.

Requirements (Intro to Policy 1)

Each Control Area shall have access to and/or operate sufficient resources to provide for a level of Operating Reserves to meet the Policy 1 requirements for Operating Reserve (Section A), Control Performance Standard (Section E), and Frequency Response Standard (Section C).

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

Sufficient Operating Reserves were maintained (and/or restored as per the Standard) to meet Regional requirements as defined in Regional procedures.

Measuring Processes

Exception Reporting
Monthly: Control Areas, Reserve Sharing Groups and all members of Reserve Sharing Groups shall send a monthly report to the Regional Reliability Council, indicating any hours that the reserves were insufficient to meet the Region's reserve requirement. (If the Regionally approved interval of measuring reserve is different than 1 hour, the Control Area or Reserve Sharing Group shall report violations against their defined interval of measurement). Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Annually: On an annual basis, if no violation has occurred during the past calendar year, Control Areas, Reserve Sharing Groups and all members of Reserve Sharing Groups shall send the Regional Reliability Council a letter verifying that no violation has occurred during the past calendar year.

Periodic Review
The Regional Reliability Council shall conduct a compliance review every three years, to ensure that Control Areas, Reserve Sharing Groups and all members of Reserve Sharing Groups polices meet the Operating Reserve requirements of Policy 1 and ensure that they are reporting deficiencies.

Investigation
At the discretion of the Regional Reliability Council or NERC an investigation may be triggered as a result of:

- Violations of Operating Reserve requirements
- Violations of the Control Performance Standard
- Violations of the Disturbance Control Standard
- Reported deficiencies of operating reserves

An investigation must be triggered within one year of the event.

100% Compliance

Control Areas, Reserve Sharing Groups and all members of Reserve Sharing Groups report no violations.

Levels of Non-Compliance

For each reported violation the following levels of non-compliance will apply:

Level 1 — The operating reserve for the measured interval was less than one hundred percent but equal to or more than ninety percent of the required operating reserve as defined by the Region.

Level 2 — The operating reserve for the measured interval was less than ninety percent but equal to or more than eighty percent of the required operating reserve as defined by the Region.

Level 3 — The operating reserve for the measured interval was less than eighty percent but equal to or more than seventy percent of the required operating reserve as defined by the Region.

Level 4 — The operating reserve for the measured interval was less than seventy percent of the required operating reserve as defined by the Region.

Compliance Assessment Notes

- Each Reserve Sharing Group shall comply with Regional procedures for Reserves as if it were a single Control Area.
- Regionally approved procedures will dictate allowable recovery period and other acceptable exclusions from carrying reserves.
- Regionally approved methods of measurement may include variation in measurement interval, included reserve types, or calculations.

Compliance Reset Period

One calendar month without a violation

Data Retention Period

- The Control Area or Reserve Sharing Group must retain hourly reserve requirements and actual reserve information for a period of 3 months.
- The Regional Reliability Council must retain all exception reports, 3-year review data and investigation results for a period of 3 years.

Monitoring Period

One calendar month

Operating Reserve Data
SAMPLE Reporting Form

1. Control Area		
	2. Date	**3. Time**
Date and time of incident (interval end)		
		Time Zone
	MW*	
4. Load Responsibility		
5. Net Generation		
6. Regional Reserve Requirement		
7. Actual Operating Reserve		
8. Reserve Deficiency		
9. Percent Deficiency		

*All data are integrated hourly values

Reporting Instructions:

1. Control Area — Enter the RRO designated acronym for the Control Area or Reserve Sharing Group.
2. Date — Enter the month (2 digits), day (2 digits), and year (2 digits).
3. Time — Enter the hour (0100, 0200, etc.) and the time zone (MST, PST, MAST, PAST, etc.).
4. Load Responsibility — Integrated hourly value of Load Responsibility.
5. Net Generation — Integrated hourly value of Net Generation.
6. Regional reserve requirements expressed in MWs
7. Actual Operating Reserve — Hourly integrated actual operating reserve.
8. Reserve Deficiency — (Line 6 minus Line 7).
9. Percent Deficiency — (Line 8 / Line 6) x 100%.

P2T1

System Operating/Interconnected Reliability Operating Limits Violations

This template has a new focus from the previous P2T1.

This new P2T1 template addresses the requirements of the Control areas and Transmission system operators to report SOL and/or IROL violations to the Reliability Coordinator.

Control Area and Transmission Operators are required to monitor their system against established limits, determined by the Control Area operator or by the Reliability Coordinator based on a wide area assessment, and report when limits are exceeded to their Reliability Coordinator along with the actions being taken to return the system to within limits. Actions could include a temporary change of ratings. The Control Areas and Transmission Operators are required to follow the directives of the Reliability Coordinator including any adjustments to the actions being taken.

Maintaining the transmission system within limits is paramount to preserve system reliability. The failure to do so was identified as a primary cause of the August 14, 2003 blackout. A clarified measure was deemed necessary by the CTTF and CCMC based on the criteria presented. The previous compliance template P2T2 and associated measures were modified in light of this need.

This is one of two new templates developed to replace the previous P2T2. Two templates were required to delineate the responsibilities and actions of the Transmission Operators or Control Area operators from those of the Reliability Coordinator.

The work on this template was coordinated with multiple reliability standards currently being developed. It is also supported by the requirements laid out in Policy 2.

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/ Interconnected Reliability Operating Limit Violations

Section Policy 2, Section A, Standard 2

Standard

When a System Operating Limit (as defined below) or an IROL (as ultimately defined by the Operating Committee) is exceeded, the Control Area Operator or Transmission Operator shall take corrective actions to return the overloaded facility to within the IROL or SOL within 30 minutes.

(The Control Area Operator or Transmission Operator shall inform the Reliability Coordinator of SOL or IROL limit violations, the actions they are taking to return the facility to within limits, and shall implement directives of the Reliability Coordinator.)

Applicable to

Control Area Operators or Transmission Operators

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

For each incident that an SOL or IROL is violated, the Control Area or Transmission Operator returned the system within 30 minutes, to within IROL, or to within an SOL for which action is required to prevent items 1–5 as defined in the Compliance Assessment Notes below:

Compliance Assessment Notes
The Reliability Coordinator provides the list of known IROL(s) to the Control Area Operator or Transmission Operator and any System Operation Limits if the violation of 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

Exception Reporting
The Control Area Operators and Transmission Operators shall report to its Reliability Coordinator all occurrences in which the Interconnected Reliability Operating Limit or System Operation Limit is exceeded.

Reliability Coordinator will report IROL and/or SOL violations (Exceeding 30 minute duration) to the RRC. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

100% Compliance

The Control Area Operator or Transmission Operator took corrective actions to return the overloaded facility to within the IROL or SOL within 30 minutes.

Levels of Non-Compliance

The Control Area Operator or Transmission Operator did not inform the Reliability Coordinator, and/or did not take corrective actions to return the overloaded facility to within the IROL or SOL within 30 minutes.

OR

The Control Area Operator or Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the overloaded facility to within the IROL or SOL within 30 minutes.

Percentage by which IROL or predefined SOL 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

Compliance Reset Period

Monthly

Data Retention Period

Three months

Monitoring Period

Monthly

P2T2

System Operating/Interconnected Reliability Operating Limit Violations

This template has an entirely new focus, so previous approvals are not included.

The Reliability Coordinator shall provide Control Areas and Transmission Operators SOLs and IROLs. The Reliability Coordinator shall then evaluate the impact, determine if correct actions are being taken, and direct any other identified actions.

This is a companion template to P2T1. P2T2 addresses the requirements of the Reliability Coordinator. Reliability Coordinators are required to identify wide area system limits and IROLs and provide those limits to the Control Areas and Transmission Operators. When the Reliability Coordinator becomes aware that a limit has been exceeded, either through their own monitoring or through notification by a control area, they are to evaluate the state of the system and the actions that are being undertaken by the Control Area or Transmission Operator. The Reliability Coordinator should direct the actions of the Control Area or Transmission Operator to return the system within limits. This includes a confirmation of the actions being taken or an adjustment based on a wide area assessment.

This template is based on the requirements in the new versions of Policy 9.

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/Interconnected Reliability Operating Limit Violations

Section Policy 2, Section A, Standard 2

Standard

When and 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 overloaded facility to within limits in thirty minutes.

If the actions being taken are not sufficient, the Reliability Coordinator shall provide direction to the Control Area Operator or Transmission Operator to return the overloaded facility

Applicable to

Reliability Coordinators

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

Verify that the Reliability Coordinator evaluated actions and provided direction to the Control Area Operator or Transmission Operators to return the system to within limits as required.

Compliance Assessment Notes
The Control Area Operator or Transmission Operator is only required to inform the Reliability Coordinator of SOL limit violations that the Reliability Coordinator has indicated might cause:

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.

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 IROL or SOL 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 SOL and or IROL, and where required, provided direction to the Control Area Operator or Transmission Operator to return the overloaded facility 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 and SOL or IROL violation in excess of 30 minutes duration.

Percentage by which IROL or predefined SOL 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

Compliance Reset Period

Monthly

Data Retention Period

Three months

Monitoring Period

Monthly

P3T3

The Interchange transaction tags in IDC must match the actual interchange transactions within the acceptable variance of Policy 3.

This template was approved by the NERC OC on September 25, 2002.

The reason for the changes to this template is that tags do not match transactions, and any transaction not in the IDC may be aggravating a system problem, and will not be included in congestion management actions.

To make this measurable, the template was tied to the Tag Audit process that uses the AIE survey. In the old template, the Sink Control Area was responsible for electronically providing tag information to the Reliability Coordinator for each Interchange Transaction. It is now aligned with present-day practices and tied to data entry into the IDC. It is less vague and easier to measure.

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/Electronic Tagging

Section Policy 3

Standard

The interchange transaction tags in IDC must match the actual interchange transactions within the acceptable variance of Policy 3.

Applicable to

Sink Control Areas

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

A tag audit will be conducted to determine the variance between the amount of transactions tagged in the IDC and the actual interchange transactions taking place at that particular time.

Measuring Processes

NERC will initiate a tag audit each month in conjunction with an AIE survey.

100% Compliance

The interchange transaction tags in IDC matched the actual interchange transactions within the acceptable variance of Policy 3.

Levels of Non-Compliance

Level 1 — All tagged transactions are in the IDC but one tag is not updated as per Policy 3 requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Level 2 — All tagged transactions are in the IDC but two tags are not updated as per Policy 3 requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Level 3 — All tagged transactions are in the IDC but three tags are not updated as per Policy 3 requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Level 4 — One or more transactions are not tagged (not in IDC) or four or more tags are not updated as per Policy 3 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 Period

Three months

Monitoring Period

One calendar year.

P4T2

Each Control Area or other Operating Authority shall provide its Reliability Coordinator with operating data to monitor system conditions and perform studies.

This template has been in the NERC Compliance Enforcement Program since 2001.

Only minor revisions were made to the levels of non-compliance for clarity.

Reliability Principle Information necessary for planning and operating interconnected Bulk Electric Systems shall be made to those entities responsible for planning and operating the system's reliability.

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 RC 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 RRO.

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

P4T4

Coordinate and report planned generator and transmission outages.

The requirement for Control Areas to report scheduled outages following the Reliability Coordinator's outage reporting requirements was put in place of general reporting guidelines. The measuring process also addresses this reporting. The Control Area must also provide this information to adjacent Control Areas.

Compliance is easier to measure with only two levels of non-compliance.

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.

Applicable to

Control Areas

Monitoring Responsibility

Regional Reliability Council (RRC)

Measure

The Control Area 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 planned outages daily, by noon, for scheduled generator and bulk transmission outages (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 IRL 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 due to a complaint of non-compliance by another Control Area. 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 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 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 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

3 months

Monitoring Period

One calendar year

P5T1

Developing, maintaining, and implementing plans for emergency operation and restoration

The reference to Policy 6 planning guides was removed since those are now contained in another template. Language was added to clarify elements that are measured during an investigation.

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 Authority 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 Coordinator is required to keep the report of the investigation on file for two years.

Monitoring Period

One calendar year.

Reporting Period

Each event

P6T1

Capacity and energy emergency plans need to be developed, maintained, and implemented.

This template has been in the NERC Compliance Enforcement Program since 2001.

Reliability Coordinators were added to the plans since they now coordinate according to Policy 9 obligations.

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 ERRIS to cope with operating emergencies.

Applicable to

Control Areas and other ERRIS as identified by the Regional Reliability Coordinator.

Monitoring Responsibility

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

Measure

Control Areas and other ERRIS 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.
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 ERRIS 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 ERRIS shall have its Capacity and Energy Emergency Plans available for a review by the Regional Reliability Council at all times

The ERRIS 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

P6T2

Developing, maintaining, and implementing plans for emergency operation and restoration

This template has been in the NERC Compliance Enforcement Program since 2001.

The term ERRIS was changed to Control Area to focus the template on Control Areas. Review cycle was changed to an annual (self-assessment) and three-year review.

The reference to Policy 6 planning guides was removed since those are contained in another template. Language was added to clarify elements that are measured during an investigation. Changes to the plan include references to coordinate actions among neighboring systems and Reliability Coordinators when the plans are implemented.

The CCMC removed the training requirement that was in the old template. Training is now covered in Template P8T3.

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 control area 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

Control Areas

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 is 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 updates.

100% Compliance

The control area 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 seven requirements.

Level 3 — N/A

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

Compliance Reset Period

One calendar year

Data Retention Period

The Control Area 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

P6T3

Plans for continuation of functions following the loss of the Primary Control facility

This is a new template based on language found in Policy 6.

This template meets a need identified in the Interim 8/14 Blackout Report. It requires a plan to continue reliable operation if the primary control facility becomes inoperable. No mandate was made for a backup control center, but the plans must ensure business and reliability continuity.

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 contingency plans 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. Interim contingency plans must be included if it is expected to take in excess of one-hour to implement the contingency plan.

3. 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.

4. 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.

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

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

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

8. 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 6, 7 and 8 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 1–8.

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 Requirements 1–5.

Level 4 — A contingency plan has not been developed, implemented, and/or 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

P8T1

Operating Personnel Responsibility and Authority

This template has been in the NERC Compliance Enforcement Program since 2001.

The CCMC made only minor word changes and reorganization to this template. No requirement or intent was changed.

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 OPERATING SECURITY 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 Checklist (Items 1–5).

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

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

Level 4 — The OPERATING AUTHORITY has written documentation that includes only one or none of the five items in the Checklist (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

P8T2

System Operator Certification

This template has been in the NERC Compliance Enforcement Program since 2000.

This template now addresses Operating Authorities instead of ERRIS to be consistent with Policy 8.

The exception for using non-certified operators ho were in training was changed to match the wording from a Personnel Subcommittee motion in January 2002 as follows:

> *While in training, an individual without the proper NERC certification credential may not independently fill a required operating position performing any tasks identified on the Critical Task Lists. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-Certified individual filling the required position.*

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 ERRIS 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*, with NERC-Certified SYSTEM OPERATORS.

Applicable to

Entity 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 ERRIS 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 performing any tasks identified on the Critical Task Lists. 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 ERRIS will be compared with NERC records.

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

Levels of Non-Compliance

Level 1 — The ERRIS 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 ERRIS 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 ERRIS 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 ERRIS 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

P8T3

Training program for NERC-Certified System Operators

This new template measures compliance to the requirements in Policy 8B that were approved by the Operating Committee in 1999 and the NERC BOT in February 2000.

Lack of system operator training was an issue identified in the 8/14 blackout and many other previous blackouts.

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 of Requirement 1 criteria.

Level 3— All of the System Shift Operators have not completed Requirement 2 training.

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

P9T1

Reliability Coordinator performs next-day study

This template was approved by the Compliance Subcommittee on September 25, 2002.

This template is revised based on the Interim 8/14 Blackout Report findings, and the work of the RCWG and the ORS in clearly defining Reliability Coordinator procedures. The standard and measure were clarified using the latest available Policy 9 related drafts to be submitted to the Operating Committee for approval. This was done to align the template to the proposed Policy 9 changes.

One difference between this template and Policy 9 is that the Policy 9 requirement for Operating Entities to share information with the Reliability Coordinator is not included in this template, it is a part of Template P4T2.

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 INTERCONNECTED RELIABILITY 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 ensure that next-day contingency analyses are carried out to ensure the bulk power system can be operated in anticipated normal and contingency 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 IRLs.

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 they conducted next-day security analyses 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 Measurements 1 and 2

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 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 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 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 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 done as required.

Monitoring Period

One calendar month

P9T2

Reliability Coordinators to take actions requested by other Reliability Coordinators.

This template was approved by the Compliance Subcommittee on September 25, 2002.

Minor changes were made to correspond to the RCWG and ORS draft changes made to Policy 9 and Appendix 9C.

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 CONTROL AREAS 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

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 CONTROL AREAS to curtail INTERCHANGE TRANSACTIONS.

Compliance Assessment Notes

The following requirements must be met when relief of transmission congestion is required:

1. Implementing relief procedures. If transmission loading progresses or is projected to violate a SOL or IRL, 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 IRL 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 IRL 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 Requirement 1 including all the sub-requirements.

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 Requirement 1 including all the sub-requirements.

Compliance Reset Period

One month without a violation

Data Retention Period

One calendar year

Monitoring Period

One calendar year

P9T3

The Reliability Coordinator has the authority to direct Operating Authorities to implement emergency procedures.

Minor changes were made to correspond to the latest RCWG and ORS changes to Policies 5, 6, and 9. These changes clarified the Reliability Coordinator authority and responsibility to implement emergency procedures.

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 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.

P9T4

Reliability Coordinator Issuance of Energy Emergency Alerts

Only minor changes were made to this template to meet the proposed changes to Policy 9 made by the ORS and RCWG.

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 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 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

Planning Template I.A.M1

Planning for system performance under normal conditions

This template was approved by the NERC BOT on June 12, 2001.

Changes to this template were minor. The text in the assessment requirements measures was converted into an easier to read bulleted list. The system simulation studies were broken out as a separate section.

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 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 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 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 for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment 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 [c] Outages
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

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.

Planning Template I.M.A2

Planning for System Performance under single contingency.

This template was approved by the NERC BOT on June 12, 2001.

Changes to this template were minor. The text in the assessment requirements measures was converted into an easier to read bulleted list. The levels of non-compliance were refined to include a corrective plan.

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 [c] Outages
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

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.

Planning Template I.A.M3

Planning for system performance under multiple contingencies

This template and standard was approved by the NERC BOT on June 12, 2001.

Changes to this template were minor. The text in the assessment requirements measures was converted into an easier to read bulleted list. The system simulation studies were broken out as a separate section. The levels of non-compliance were refined to include a corrective plan.

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 [c] Outages
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

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.

Planning Template I.A.M4

Planning for system performance under extreme contingencies

This template and standard was approved by the NERC BOT on June 12, 2001.

Changes to this template were minor. The text in the assessment requirements measures was converted into an easier to read bulleted list. The system simulation studies were broken out as a separate section. The levels of non-compliance were refined to include a corrective plan.

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. Demonstrate that system performance meets Table I for Category D contingencies.
6. Include existing and planned facilities.
7. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
8. Include the effects of existing and planned protection systems, including any backup or redundant systems.
9. Include the effects of existing and planned control devices.
10. 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		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

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.

Planning Template I.B.M1

Self assessment of regional and interregional reliability

This standard was approved by the NERC BOT on June 12, 2001.

The old text in the measures section was put into a bulleted listing for clarity. The reliability assessment text was also put into a bulleted listing. Direction was added on how longer-term studies should be performed.

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 are 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

Planning Template I.F.M1

Define and document disturbance monitoring requirements

This standard was approved by the NERC BOT on June 12, 2001.

The changes made to this template include:
Under the measurement requirements, removed the "for example" and listed the items for some requirements of the list.
Also added a five-year minimum for acting on documentation where no time was listed before.

The word “Implementation” was added to the category since this template also addresses the plan implementation.

The data request time was changed from 5 business days to 30 days to be uniform with other templates.

An effective date of 18 months from approval by the NERC BOT was added to allow regions time to meet the blackout recommendation that ties with this template.

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)

Criteria for the location of monitoring equipment:

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

Testing and maintenance requirements:

1. Responsibility for maintenance and/or testing

Documentation requirements:

2. 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

Effective Date

18 months from NERC BOT approval

Planning Template II.A.M5

Development of steady-state models

This template was approved for field-testing by the NERC PC on November 14, 2000.

In this template, the CCMC clarified the regional entities to which it applies, and changed the levels of non-compliance to reflect the current MMWG plan to penalize for late posting.

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. The Regions shall develop and maintain a library of solved (converged) regional steady-state system models needed to analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. 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 an 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. The most recent solved (converged) steady-state models shall be provided to the Regions and NERC on request (30 days).

Applicable to

Individual Regions submitting models/data as part of a process to develop steady-state system models for the NERC Interconnection they are a part of.

Items to be Measured

Development of Regional 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 case 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

Planning Template II.A.M6

Development of dynamics models

This template was approved for field-testing by the NERC PC on November 14, 2000.

The CCMC clarified the regional entities to which this template applies, and changed the levels of non-compliance to reflect current the MMWG plan to penalize for late posting.

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. The Regions shall develop and maintain initialized (with no faults or system disturbances) regional dynamics system models for at least two timeframes (present or near-term model and a future or longer-term model) and other models, 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. Sl, M5. Within an 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. The most recent initialized (approximately 25 seconds, no-fault) models shall be provided to the Regions and NERC on request (30 days).

Applicable to

Individual Regions submitting models/data as part of a process to develop dynamic system models for the NERC Interconnection they are a part of.

Items to be Measured

Development of Regional 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 case 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

Planning Template II.C.M1

Methodology for determining electrical facility ratings

This standard was approved by the NERC BOT on June 12, 2001.

The CCMC changed the measurements to include equipment ratings. The text in the measure section was altered into numbered statements and included equipment ratings with the facility ratings. Non-compliance levels were slightly changed to reflect the importance of the methodologies.

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 (or methodologies) used to determine their electrical facility/equipment ratings. Further, the methodology (ies) shall be compliant with applicable Regional requirements.

The documentation shall address and include:

1. The methodology(ies) used to determine facility/equipment ratings 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/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 (ies) used to determine transmission facility/equipment ratings shall be provided to the Regions and NERC on request (30 days).

Applicable to

Facility owners

Items to be Measured

Methodology(ies) used for determining facility/equipment ratings.

Timeframe

On request (30 days).

Levels of Non-Compliance

Level 1 — Facility rating methodologies do not address one of the requirements listed in the above Measurement M1.

Level 2 — N/A

Level 3 — Facility rating methodologies do not address two of the requirements listed in the above Measurement M1.

Level 4 — Facility rating methodologies do not address three or more of the requirements listed in the above Measurement M1 or no facility 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.

Planning Template III.A.M4

Transmission protection system maintenance and testing program

This standard was approved by the NERC BOT on October 16, 2001.

Changes to this template include:

Creating a list of specific equipment to be included in the testing and maintenance program.

Identifying specific elements the testing and maintenance program must include.

Changing levels of non-compliance to recognize that relay testing performed is more important than documentation that goes with the work, as long as records show work was performed. Other protection-based templates also show this change.

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. Frequency of testing
e. Schedule for system testing
f. Schedule for system maintenance
g. 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 — Complete 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.

Planning Template III.D.M1

Development and documentation of underfrequency load-shedding programs within and among regions.

This template was approved for field-testing by the Planning Committee on November 14, 2000.

Changes to this template were formatting the old requirements text into a bulleted listing for clarity and removing old measure M1.e due to vagueness. Non-compliance levels were modified slightly for clarity.

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

Planning Template III.D.M2

Assuring consistence of entities with Regional underfrequency load shedding requirements

This standard was approved by the NERC BOT on October 16, 2001.

The only change to this template was to the levels of non-compliance to measure consistency of percentage of load shed.

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.

Planning Template III.D.M3

Documentation and implementation of underfrequency load shedding program

This standard was approved by the NERC BOT on October 16, 2001.

The CCMC changed the levels of non-compliance to recognize that relay testing performed is more important than documentation that goes with the work, as long as records show work was performed. Other system protection-based templates also show this change.

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.

Planning Template III.E.M3

Assess the design and effectiveness of the underfrequency load shedding program

This template was approved for field-testing by the Planning Committee November 14, 2000.

The changes to this template include:

The old text in the requirements was reformatted into a bullet listing for easier reading.

The CCMC added two more requirements, one to use simulations to demonstrate I.A. performance, and a review of voltage set points and timing.

These additions were deemed to be obvious to planners, but need to be stated for compliance purposes.

Non-compliance levels changed to only a level 4 addressing the requirements.

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.

Planning Template III.E.M4

Undervoltage load shedding relay system maintenance and testing

This standard was approved by the NERC BOT on October 16, 2001

The CCMC changed the levels of non-compliance to recognize that relay testing performed is more important than documentation that goes with the work, as long as records show work was performed. Other system protection-based templates also show this change.

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 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. Frequency of testing

e. Schedule for system testing

f. Schedule for system maintenance

g. 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.

Planning Template III.F.M6

Documentation and implementation of special protection system programs.

This standard was approved by NERC BOT on October 16, 2001.

The CCMC created a list of specific equipment and elements to be included in the testing and maintenance program.

The levels of non-compliance were modified to recognize that relay testing performed is more important than documentation that goes with the work, as long as records show work was performed. Other protection-based templates also show this change.

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 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. Frequency of testing

e. Schedule for system testing

f. Schedule for system maintenance

g. 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.

Planning Template IV.A.M4

Establish, maintain, and document a Regional blackstart program

This template was approved for field-testing by the Planning Committee on November 14, 2000

The CCMC formatted some requirements into a bulleted list for easier reading. The requirement for annual testing of each unit was changed to testing one-third of the units each year.

The requirement to submit a blackstart diagram was removed due to critical infrastructure disclosure considerations. The requirement to review and update the plan every five years was clarified. Non-compliance levels now account for plan incompleteness in levels two and four.

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

Planning Template IV.A M4

Document blackstart unit test results.

This template was approved for field-testing by the NERC PC on November 14, 2000

The CCMC added a statement expecting that a unit that fails the test will be fixed and retested or it will no longer be considered a blackstart unit. The blackstart test was tied to the requirements in the Regional Blackstart Plan for clarity.

The requirement for annual testing was changed to reflect the requirement in template IV.A.M1 to test one-third of the units each year.

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 balckstart requirements. It is expected that if a unit fails a test, that unit will be fixed and retested 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 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: on request to the Region and NERC (30 days).

Levels of Non-Compliance

Level 1 — Documentation of the testing was provided but the startup and operational testing was only partially performed.

Level 2 — Startup and operation testing of each blackstart generating unit was performed but documentation was incomplete.

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

Level 4 — Startup and operation testing of blackstart generating unit(s) was not performed as required in the Regional Plan, or no documentation is available.

Compliance Monitoring Responsibility

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

Vegetation Management

Vegetation management program and outage reporting

This is a new template therefore there are no prior approvals. This template was created in response to NERC BOT Blackout Recommendations 4a, b, and c approved on February 10, 2004

The measures were based on the WECC vegetation management program, with some modifications. The requirement states that each transmission owner shall have a vegetation management program. The measures hold the transmission owner accountable to following and implementing that program.

The reporting measures require that all vegetation related outages be reported. The reporting process will be designed to separate outages caused directly by vegetation from those that included other factors, such as line overloading, icing, or broken insulators.

Vegetation Management Program

Brief Description Vegetation management program for transmission owners

Requirement

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 and obstruction removal procedures
- documentation procedures
- maintenance schedule

Applicable to

Transmission Owners

Reporting Requirements

Three-year Audit
Each transmission owner shall make available their vegetation management program and the documentation of work completed.

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

Periodic Reporting
Transmission owners shall report vegetation-related line outages on transmission circuits 230 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. Regions shall submit an annual compliance report to NERC on an annual basis using the NERC reporting process.

To provide consistency among systems reporting, the following definitions shall be used:

- An outage shall be defined as any line operation caused by relay action
- A vegetation-caused outage is defined as a fault caused by vegetation growing into, falling into, blowing into, or any other reason contacting a line operating within the line's limits.
- A fault on an individual line shall be reported as one outage for any outage for any number of actual outages within a 24-hour period caused by the same vegetation. A trip followed by a successful reclose shall be considered one outage.

Items to be Measured

The vegetation management program documentation contains the following elements:

- Inspection requirements
- trimming clearances and obstruction removal procedures
- documentation procedures
- maintenance schedule

Vegetation Management Program

The transmission owner performs vegetation program maintenance according to the requirements and procedures contained in the program.

All vegetation-related transmission line trips on lines of 230kV or higher and any other lower voltage lines designated by the Regional Reliability Council to be critical to the reliability of the electric system.

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 during the past calendar year that is described in the Vegetation Management Program.

Periodic Reporting
All vegetation-related transmission line trips on lines of 230kV 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 20^{th} 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 above.

Self-Certification
The transmission owner performed all maintenance as described in the Vegetation Management Program

Periodic Reporting
No vegetation-related transmission line outages of 230 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 occur during a calendar quarter.

Levels of Non-Compliance

Level 1 — Two vegetation-related transmission line outages of 230 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 occurred during a calendar quarter, or the transmission owner did not perform the necessary maintenance described in the vegetation management maintenance program and according to the schedule as reported via self-certification during the calendar year.

Level 2 — Not applicable.

Level 3 — The transmission owner vegetation management program is not complete.

Level 4 — Three or more vegetation-related transmission line outages of 230 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 occur during a calendar quarter, or The transmission owner has no vegetation management program.

Vegetation Management Program

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.

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

March 19, 2004

Proposed P3 T3 Compliance Template

Dear Compliance Template Task Force,

At the last meeting of the NERC Interchange Subcommittee, we reviewed the August 14, 2003, AIE – E-Tag audit results and identified some of the same inconsistencies between the AIE Net Scheduled Interchange and the E-Tag information in IDC as those noted in the audit responses from the Control Areas. There are instances where the physical path of a transaction reflected correctly in the E-Tag, might be different than the Control Area accounting of the Net Scheduled Interchange in the AIE survey. For example, one Control Area noted that over 800 MWh of load, served by other Control Areas within its transmission system, is tagged as if the scheduled interchange is sinking in that Control Area so that the IDC is provided accurate information on the physical flow. The scheduled interchange reflected back to the responsible Control Areas in the AIE survey reporting created significant discrepancies between the E-Tag information and the AIE Net Scheduled Interchange.

On a conference call today, the Interchange Subcommittee reviewed the proposed P3 T3 Compliance Template and concluded that we cannot support the implementation of the compliance template, as it is technically invalid. The Interchange Subcommittee found that the comparison of the E-Tag audit information to the AIE survey's Net Scheduled Interchange is an "apples-to-oranges" comparison. In addition to the example provided above, a valid comparison would have to address among other items:

1) Point-to-point transactions internal to a Control Area
2) DC Ties
3) Reserve Sharing events less than an hour
4) Dynamic Schedules
5) Mid-hour changes to the E-Tag
6) Self-provided losses in the E-Tag

The Interchange Subcommittee requests that the Compliance Template Task Force not submit the P3 T3 Compliance Template for approval at the NERC Operating Committee meeting. We ask that the task force allow us the opportunity, and accept our commitment, to thoroughly discuss the Interchange Standards presented in Policy 3 and bring back recommended templates after our April meeting.

Regards,

Doug Hils

Doug Hils
Chairman, Interchange Subcommittee

March 29, 2004

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/ Electronic Tagging

Applicable to

Control Areas

Standard

Except where noted in Policy 3, the Control Area shall ensure that all Scheduled Interchange is tagged and provided to those entities responsible for planning and operating the systems reliably, prior to the implementation of scheduled interchange between Control Areas.

[See Policy 3, "Interchange" Section A.2 and 2.1]

Monitoring Responsibility

Regional Reliability Council (RRC)

Measurement

Every Control Area must meet the 100% tagging requirements for all scheduled interchange between Control Areas per Policy 3.

[See Policy 3, "Interchange" Section A.2 and 2.1]

Measuring Processes

Periodic audits as prescribed by the NERC Tag audit procedure

The Control Area shall demonstrate 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 - none

Level 2 - none

Level 3 – none

Level 4 – One or more energy schedules implemented as Scheduled Interchange were not tagged as required in Policy 3.

Penalties/sanctions
To be decided

Compliance Reset Period
One calendar year without a violation from the time of the violation

Data retention requirements
Three months

Multiplier: 1.0

Occurrence Period –One Calendar year

March 29, 2004

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 Schedule

Applicable to

Sink Control Area operating to one or more Dynamic Schedules

Standard

From Policy 3: DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.)

The Sink Control Area for a Dynamic Schedule shall ensure that the PURCHASING-SELLING ENTITY provides a revised E-Tag whenever the projected energy transfer of the Dynamic Schedule changes by 25% or more from the expected average MW profile for each hour provided in the E-Tag.

Monitoring Responsibility

Regional Reliability Council (RRC)

Measurement

The Sink Control Area will demonstrate 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 Schedule integrated over each hour, was 25% or more for two consecutive hours.

Measuring Processes

Periodic audit as prescribed by the NERC Tag audit procedure

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 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 by the PURCHASING-SELLING ENTITY.

Levels of Non-Compliance

Level 1 – One tag was not updated as per Policy 3 requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Level 2 – Two tags were not updated as per Policy 3 requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Level 3 – Three tags were not updated as per Policy 3 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 as per Policy 3 requirement that a change in the hourly energy profile of 25% or more requires a revised tag.

Penalties/sanctions

To be decided

Compliance Reset Period

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

Data retention requirements

Three months

Multiplier: 1.0

Occurrence Period –One Calendar year

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.

Item 4. Dynamic Transfers – Doug Hils

Background

The Operating Committee approved Version 1 of the Dynamic Transfer Reference Document. The OC also asked the Interchange Subcommittee to prepare a Dynamic Transfer Catalog. The OC actions were in response to a letter from the Interchange Subcommittee that identified issues surrounding dynamic transfers and the actions the subcommittee plans to take to address those issues.

Attachment

4a. Interchange Subcommittee Actions on Dynamic Transfers, March 3, 2004

Background

A few revisions have been proposed to the white paper. The subcommittee should review these proposals and revise the white paper as necessary. Mike Oatts and Deanna Phillips will lead the discussion.

Attachments

4b1 Emails on potential revisions to the white paper

4b2 Mike Oatts revisions to the white paper

Interchange Subcommittee Actions on Dynamic Transfers

Background

The Interchange Subcommittee (IS) is responsible for NERC Policy 3, "Interchange" as well as administering the E-Tag system and specification. Policy 3 requires that scheduled interchange, with few exceptions, is tagged prior to schedule implementation and provided to the Interchange Distribution Calculator (IDC) through the E-Tag systems.

Dynamic transfer is the provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a dynamic schedule or pseudo-tie. Though dynamic transfers have been implemented between Control Areas for years, implementation guidelines and requirements are needed as the industry has various interpretations on how to implement, operate, and account for dynamic transfers. Setting guidelines and requirements for dynamic transfers would reinforce the coordination of information necessary to ensure that the operation to and accounting of dynamic schedules and pseudo-ties is consistent between all parties to the dynamic transfer.

Dynamic transfers implemented as pseudo-ties do not require tagging because the implementation should be captured in the base system model. Pseudo-ties are accounted for in a control areas' Net *Actual* Interchange similar to interconnection ties. Dynamic transfers implemented as dynamic schedules are required to be tagged for the projected interchange and provided to the Interchange Distribution Calculator (IDC). Dynamic schedules are accounted for in a control areas' Net *Scheduled* Interchange.

Scheduled interchange that is not properly tagged will not be entered into the IDC. This can result in TLR curtailments that do not effectively relieve the congested flowgate, or curtailments that do not align with the transmission service priorities specified in the *pro forma* tariff, or both. The Interchange Subcommittee plans a number of actions, both long-term and short-term, to address the dynamic transfer issues.

AIE – E-Tag Audit

The NERC compliance group conducted the first ever E-Tag audit in conjunction with an AIE audit called by the Resources Subcommittee. The audit was for the seven hours prior to and including the August 14, 2003 blackout. The AIE – E-Tag audit compared the net E-Tag schedules as provided to the IDC, to the Net Scheduled Interchange from the AIE surveys as accounted for by the control areas. Although the audits did not compare exact sets of data, it was assumed that the difference between the two data sets would be minimal.

The audits revealed significant differences over 1,000 MWs for a few control areas and raised concerns that some dynamic schedules were not tagged or revised properly. Based on these results, NERC compliance issued a follow-up audit where control areas were asked to reconcile the differences between the two sets of data and to categorize their untagged schedules. This audit's results do not definitively identify Policy 3 violations. The Interchange Subcommittee plans to further analyze the responses from the control areas that averaged over 100 MWs of difference over the seven audit hours.

System Modeling and Simulation Analysis Team

Bob Cummings, NERC's director of reliability assessments and support services, is involved with the outage investigation and facilitates the Modeling and System Studies Team (M&SST). This team is modeling and conducting transmission studies in the outage areas. The M&SST has encountered a number of problems while doing these studies such as accounting for dynamic transfers and jointly owned units, and how untagged interchange may cause problems for real-time security analysis. The M&SST notes:

Analysis conducted of the Eastern Interconnection tags for August 14 highlighted an ongoing discrepancy between the total interchange transactions between control areas and the electronic tags. A tag audit was conducted by NERC in conjunction with an Area Interchange Error (AIE) survey for a number of hours on August 14. That tag audit showed large discrepancies caused mostly by capacity transactions related to jointly owned generating units and remotely metered control area loads. For 15:00 EDT, the discrepancy for FirstEnergy imports was over 2,400 MW of untagged transactions for their shares of Beaver Valley nuclear plant and Seneca pumped storage plant. Such large discrepancies create errors in system security analyses of other system operators' state estimators, and errors in the IDC solutions for TLR.

The M&SST made the following recommendation:

The regulations for tagging of dynamic schedules and pseudo-ties should be strengthened and monitored for compliance.

NERC Outage Recommendation

The M&SST recommendation was rolled into the **NERC Recommendations to Prevent and Mitigate the Impacts of Future Cascading Blackouts, Recommendation 14: Improve System Modeling Data and Data Exchange Practices.**

The after-the-fact models developed to simulate August 14 conditions and events indicate that dynamic modeling assumptions, including generator and load power factors, used in planning and operating models were inaccurate. Of particular note, the assumptions of load power factor were overly optimistic (loads were absorbing much more reactive power than pre-August 14 models indicated). Another suspected problem is modeling of shunt capacitors under depressed voltage conditions. Regional reliability councils should establish regional power system models that enable the sharing of consistent, validated data among entities in the region. Power flow and transient stability simulations should be periodically compared (benchmarked) with actual system events to validate model data. Viable load (including load power factor) and generator testing programs are necessary to improve agreement between power flows and dynamic simulations and the actual system performance.

Interchange Subcommittee plans to address Dynamic Transfers

Interchange Subcommittee Review of the AIE – E-Tag Audit

After reviewing the August 14, 2003, AIE – E-Tag audit results, the Interchange Subcommittee identified some of the same inconsistencies between the AIE Net Scheduled Interchange and the E-Tag schedules as those noted in the audit responses. For example, one control area noted that over 800 MWh of load, served by other control areas within its transmission system, is tagged as if the scheduled interchange is sinking in that control area. Therefore, the IDC is provided accurate information on the physical flow of the 800 MWh. The scheduled interchange reflected back to the responsible control areas in the AIE reporting created some discrepancies between the E-Tag and the AIE Net Scheduled Interchange. The Interchange Subcommittee will continue to investigate the various accounting methods to provide an accurate measurement of compliance to Policy 3 for coordinated interchange scheduling, including the provision of accurate scheduling information to the IDC.

Although the AIE – E-Tag comparison was not an "apples-to-apples" comparison of scheduled interchange, the comparison still uncovered some discrepancies. Though required in Policy 3, the audit results indicate that some dynamic schedules were not properly tagged and subsequently were not reflected in the IDC. In addition, the AIE – E-Tag results and control areas responses indicate that the projected interchange reflected in the E-Tag for some dynamic schedules, was not updated when the dynamic schedule exceeded the 25% boundary set by Policy 3. Policy 3 requires the Purchasing-Selling-Entity (PSE) update the E-Tag when the dynamic schedule varies by 25% or more, when compared against the projected interchange in the E-Tag. These discrepancies and those identified by the M&SST reinforce the need to move forward with the Interchange Subcommittee's recommendations to address the implementation of dynamic transfers.

The Interchange Subcommittee will continue to review the audit responses and request additional explanations from those control areas whose responses have not clearly demonstrated non-compliance to Policy 3 requirements. If the Interchange Subcommittee determines that any party violated Policy 3, data supporting the subcommittee's determination will be provided to NERC's compliance group for further action.

Dynamic Transfer White Paper

A subgroup of the Interchange Subcommittee (Dynamic Transfer Task Group) has drafted a Dynamic Transfer White Paper that provides guidance for the implementation of dynamic transfers. The Interchange Subcommittee plans to submit the white paper to the Operating Committee for approval as a reference document at its March 2004 meeting. The white paper will provide guidance for future implementations of dynamic transfers, and may be used by the Interchange Subcommittee as background to draft policy revisions, develop an associated appendix, draft a SAR on dynamic transfer, or draft compliance templates.

Letter to the Industry on Policy 3 and Dynamic Transfers

The Interchange Subcommittee periodically surveys the industry on possible enhancements to the E-Tag system. One recent survey question dealt with the addition of a "checkout" function to E-Tag also asked, "Do you have any untagged interchange?" "If so, what schedules are untagged?" A number of responses seemed to directly violate Policy 3. The Interchange Subcommittee will write a letter to the industry stating the tagging requirements in Policy 3. The letter will also be used to prepare the industry for the upcoming Dynamic Transfer Catalog Survey.

Dynamic Transfer Review Process and Catalog

The Interchange Subcommittee intends to conduct an industry survey to identify the current control area configurations for dynamic transfers implemented to accommodate jointly owned units, remote loads, remote generation, supplemental regulation service, and AGC interchange, among other uses. The control areas will be required to provide detailed operating and accounting methods for each dynamic transfer along with the 'associated' control area(s) involved in the dynamic transfer. The Interchange Subcommittee will review the data to ensure among other items that:

- Entities are accounting for transfers of the same MW in the same way
- Transfers are handled correctly in the ACE equations
- Transfers that should be tagged are tagged.

Upon NERC Operating Committee approval of the Dynamic Transfer White Paper as a reference document, the Interchange Subcommittee intends to propose a review process for the implementation of new dynamic transfers. The Interchange Subcommittee would also propose that a task force or working group be established, with members from the IS, DFWG, IDCWG, RS, RCWG, ORS, RS, and NAESB, to oversee the review process. The intent is not to create a bottleneck for implementing dynamic transfers, but to provide a review to ensure that all parties to the dynamic transfer are following the requirements stated in Policy 3 and other NERC policies.

Comparing EMS, E-Tag and AIE Data

In the Interchange Subcommittee's discussion of the current AIE – E-Tag audit process, the subcommittee evaluated how future audits may be structured to ensure that all interchange is accounted for correctly, how the submitted audit data could be quickly analyzed, and what data is needed for the subcommittee to determine if violations to Policy 3 had occurred.

The Interchange Subcommittee will continue to discuss revisions to the audit process to address:

- Discrepancies between Net Scheduled Interchange as implemented in the Energy Management System (EMS) and E-Tag data provided to the IDC.
- Discrepancies between Net Scheduled Interchange as implemented in the EMS and Net Scheduled Interchange as accounted for in the AIE.
- Proper operation and accounting of pseudo-ties by all parties.
- Proper operation and accounting of dynamic schedules by all parties.
- Scheduled Interchange required to be provided to the IDC

The subcommittee is considering an audit that would require the submittal and analysis of AIE, E-Tag, **and EMS data**.

Policy 3 Revisions and Compliance Templates

Based upon the lessons learned from the dynamic transfer review process and catalog, the Interchange Subcommittee intends to add requirements to Policy 3 to address dynamic transfers as necessary and strengthen the current Tagging requirements for dynamic schedules. The subcommittee is currently drafting compliance templates, including performance measures, directed toward the implementation of schedules into the Energy Management System, proper tagging of dynamic schedules, the handling of pseudo-ties, and provisions for ensuring accurate data is provided to the IDC.

From: Potishnak, Mike [mpotishnak@iso-ne.com]
Sent: Monday, April 12, 2004 4:04 PM
To: Gordon Scott; dynamicschedule@nerc.com; interchange@nerc.com
Cc: Karl Tammar (E-mail); Potishnak, Mike; Deanna Phillips (E-mail); Tom Pruitt (E-mail)
Subject: RE: DT White Paper sign conventions

I agree that the additions to Appendix C are necessary and sufficient.

I agree that the additions and changes to Appendix D are necessary and sufficient.

With respect to Appendix E, I agree with the changes and additions. However, the next to the last sentence:

"Note that all requirements for dynamic scheduling must be observed while providing supplemental regulation service."

I disagree strongly with it and request that it be dropped. When a non-zero expected value exists for a dynamic transfer, and the condition is expected to persist for an hour, a pseudo-tie is inferior and a dynamic schedule is better to promote analyses such as IDC. There is often a known buyer and seller and tagging is of value.

But when it is symmetric bidirectional regulation, the best guess is zero, nonzero values will exist subhourly and change signs (just like untagged normal control area ACE values do all the time without any tagging requirements!!!!), and there is no benefit to tagging. In fact, providing a tag may create a delusion of predictability that is not warranted. There is no buyer or seller of energy, its just a transient exchange between control areas. I would prefer a pseudo-tie over a dynamic schedule for supplemental regulation so that there is no illusion that it is predictable and there is one less tag to deal with during any auditing. Therefore, I recommend adding an appendix to show how supplemental regulation works with pseudo-ties.

It would be worthwhile to add a numeric example of how supplemental regulation works its way through the labynthine equations.

Finally, I hope that we can address the concerns i raised in the main body of the document in this pass as well.

If someone sends me the information and my presence would be useful, I'd be glad to participate if it does not conflict with another conference call that I have at 130 PM EDT

-----Original Message-----
From: Gordon Scott [mailto:Gordon.Scott@nerc.net]
Sent: Monday, April 12, 2004 2:09 PM
To: dynamicschedule@nerc.com; interchange@nerc.com
Cc: Karl Tammar (E-mail); Potishnak, Mike; Deanna Phillips (E-mail); Tom Pruitt (E-mail)
Subject: DT White Paper sign conventions

All,

Please review the revisions from Mike Oatts. We will discuss the revisions on tomorrow's IS agenda conference call.

Thanks, Gordon.

Gordon -

I finally found some time to look at the Appendices C, D, and E in the Dynamic Transfer White Paper. I also considered items 14, 16 and 17 (attached below) of Mike Potishnak's 3/19/04 email to Karl Tammer that you sent to me per your request. I also tried to use existing policy Appendix 1A as the basis for my assumptions. The sign convention for subsection B for JOU's in Appendix 1A was somewhat confusing so I based my assumptions on the discussion in subsection D and assumed the equation in the white paper for Dynamic Schedules was correct (which it appeared to be). Doing that led me to assume that all quantities in the equations for the White Paper Appendices C and D were to be positive. Based on these assumptions, my analysis agrees with Mike's comments and with my original contention that the signs for the Pseudo-tie appendix D were backwards.

I extracted the Appendices C, D, and E from an earlier version of the White Paper so I could work with a Word Version and made the changes shown in the attached document (I turned Tracking on). There were some format changes to clean it up but basically just had to add statements concerning the assumption of positive values and fixing the signs for the NIA term of the Appendix D - Pseudo-Ties. I also tried to put in some wording on Appendix E to help with Mike's concern about clarity of signs and the effect on ACE of the Supplemental Regulation Terms. You will note that I did not keep the "examples" that were added to the last version of the White Paper. I thought they were confusing and did not add anything to the paper. Some examples would be good but those were not the right ones in my opinion. If someone wants them in then Barbara or someone can re-add them.

Sorry for the delay in getting to this but I hope better late than never.

Let me know if you have nay questions.

Mike Oatts

-----Original Message-----
From: Gordon Scott [mailto:Gordon.Scott@nerc.net]
Sent: Tuesday, March 30, 2004 3:18 PM
To: Oatts, Mike L.; Vice, Raymond L.
Subject: DT White Paper sign conventions
Importance: High

Mike and Raymond,

As you know the DT white paper was approved as a reference document by the OC at their March 2004 meeting. Before adding the white paper to the Operating Manual as a reference document a check should be make to the calculations in the appendixes to ensure the sign conventions are consistent. The following notice was added to the white paper's appendixes:

[See also, Appendix 1A Subsection B - "The Area Control Error (ACE) Equation" for examples on sign conventions used in the equations.]

I would like to be able to post the white paper by Friday of this week. If someone at Southern could review the appendixes it would be very helpful.

Version 1 of the white paper is posted in the Operating Committee agenda.

Thanks, Gordon.

****
Comments from Mike Potishnak's 3/19/04 email to Karl Tammer

14. [technical error] The signs are backwards for the dynamic transfer adjustments on page 18. For example, let's assume that the attaining and native areas have initial ACE values of zero and also their net schedule and net actual interchanges are zero. These conditions exist just prior to noon on the day that a load of 100 MW will begin to be dynamically transferred to the attaining area. At noon, the attaining area becomes responsible for the 100 MW of the load in the native area. For the attaining area,
NIA new = NIA old + NIaptle = 0 + 100 = 100 MW. With the attaining area's schedule remaining the same, the actual interchange goes up to +100, as will its ACE.   This is not correct, we want its ACE to go to -100 MW so it will supply the newly added load. Similarly, the native area will get an erroneous ACE of -100 instead of +100. When the load gets moved from the native area to the attaining area, the native area's ACE should get more positive and the attaining area's ACE should get more negative. This does not happen as written in this formula! Additional examples can be provided upon request.

16. [simple typo] The last 2 terms of the NIs equation on page 21 should be
NIsrse and NIsrsi

17. [lack of clarity] The two terms of item 16 above should be better defined in terms of ACE and sign.   For example, suppose the area purchasing regulation service has an initial ACE of + 50 MW, and the seller of regulating service has an initial ACE of -10 MW. If the provider can provide up to an absolute value of 30 MW of supplemental regulation service by contract, we want the purchaser's ACE to go from +50 to +20, and the seller's ACE goes from -10 to +20.

Chasing down the thread of logic here, the purchaser wants -30 MW of regulation service. When you plug -30 into NIsrse, its preceding negative sign changes its value to a +30 MW. When the schedule is made 30 MW more positive, the ACE will get more negative, which is the desired effect.
Basically, the sign of the regulation service purchased is the opposite of purchaser's prevailing ACE. We need to write this so it cannot be misunderstood, and provide complete examples.

With respect to the seller, the -30 is added to its schedule, effectively reducing the schedule, making its ACE get more positive.

Appendix C – ACE Equation Modifications – Dynamic Schedules

ACE Equation Modifications

Typically:

$ACE = (NI_A – NI_S) – 10F_b (F_A – F_S) – I_{ME}$

where:

NI_A = Net Actual Interchange

NI_S = Net Scheduled Interchange

F_b = Control Area Frequency Bias

F_A = Actual Frequency

F_S = Scheduled Frequency

I_{ME} = Meter Error Correction

For a DYNAMIC SCHEDULE the NI_A remains unchanged, but the NI_S term becomes :

$NI_S = NI_s – NI_{SDSGE} + NI_{SDSGI} + NI_{\cancel{SDSLE}SDSLE} – NI_{SDSLI}$

where :

NI_s = Net sum of non-dynamically scheduled transactions

NI_{SDSGE} = sum of dynamically scheduled generation external to the CONTROL AREA (ATTAINING CONTROL AREA).

NI_{SDSGI} = sum of dynamically scheduled generation internal to the CONTROL AREA (NATIVE CONTROL AREA).

NI_{SDSLE} = sum of dynamically scheduled load external to the CONTROL AREA (ATTAINING CONTROL AREA).

NI_{SDSLI} = sum of dynamically scheduled load internal to the CONTROL AREA (NATIVE CONTROL AREA).

and where values for all generation and load terms are assumed to be positive quantities.

See also Operating Manual, Appendix 1A, Subsection D – "The Area Control Error (ACE) Equation" for further discussion of the required ACE equation modifications using dynamic schedules.

Appendix D – ACE Equation Modifications – Pseudo-Ties

ACE Equation Modifications

Typically:

$ACE = (NI_A - NI_S) - 10F_b\,(F_A - F_S) - I_{ME}$

where:

NI_A = Net Actual Interchange

NI_S = Net Scheduled Interchange

F_b = Control Area Frequency Bias

F_A = Actual Frequency

F_S = Scheduled Frequency

I_{ME} = Meter Error Correction

For PSEUDO-TIE/AGC INTERCHANGE the NI_S remains unchanged, but the NI_A term becomes:

$NI_A = NI_a \cancel{-} \underline{+} NI_{APTGE} \cancel{+} \underline{-} NI_{APTGI} \cancel{+} \underline{-} NI_{APTLE} \cancel{-} \underline{+} NI_{APTLI}$

where:

NI_a = Net sum of tie line flows

NI_{APTGE} = sum of AGC INTERCHANGE generation external to the CONTROL AREA (ATTAINING CONTROL AREA).

NI_{APTGI} = sum of AGC INTERCHANGE generation internal to the CONTROL AREA (NATIVE CONTROL AREA).

NI_{APTLE} = sum of AGC INTERCHANGE load external to the CONTROL AREA (ATTAINING CONTROL AREA).

NI_{APTLI} = sum of AGC INTERCHANGE load internal to the CONTROL AREA (NATIVE CONTROL AREA).

and where values for all generation and load terms are assumed to be positive quantities.

Appendix E – ACE Equation – Supplemental Regulation Service as a Dynamic Schedule

Supplemental regulation service is when one control area provides all or part of the regulation requirements of another control area. The control areas implement a dynamic schedule incorporating the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the scheduled interchange component of the ACE equation for both control areas. Care should be taken to maintain the proper sign convention to ensure proper control, with the control area purchasing regulation service subtracting the supplemental regulation service from their ACE while the control area providing the service adds it to theirs.

If the supplemental regulation service includes a calculated assistance between the native control area and the attaining control area for recovery from the loss of generation, then both control areas are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Policy 1.

Note that all requirements for dynamic scheduling must be observed while providing supplemental regulation service. ACE equation modifications required for supplemental regulation service:

ACE Equation Modifications

Typically:

$ACE = (NI_A – NI_S) – 10F_b (F_A – F_S) – I_{ME}$

where:

NIA = Net Actual Interchange

NIS = Net Scheduled Interchange

Fb = Control Area Frequency Bias

FA = Actual Frequency

FS = Scheduled Frequency

IME = Meter Error Correction

For a DYNAMIC SCHEDULE the NI_A remains unchanged, but the NI_S term becomes:

$NI_S = NI_s – NI_{SDSGE} + NI_{SDSGI} + NI_{SDGLE} – NI_{SDSLI}$

where:

NI_s = Net sum of non-dynamically scheduled transactions

NI_{SDSGE} = sum of dynamically scheduled generation external to the control area (ATTAINING CONTROL AREA).

NI_{SDSGI} = sum of dynamically scheduled generation internal to the control area (NATIVE CONTROL AREA).

NI_{SDSLI} = sum of dynamically scheduled load internal to the CONTROL AREA (NATIVE CONTROL AREA).

For a DYNAMIC SCHEDULE used to implement SUPPLEMENTAL REGULATION SERVICE the NI_A remains unchanged, but the NI_S term becomes:

$$NI_S = NI_s - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI}$$

where:

NI_s = Net sum of non-dynamically scheduled transactions

NI_{SDSGE} = sum of dynamically scheduled generation external to the CONTROL AREA (ATTAINING CONTROL AREA).

NI_{SDSGI} = sum of dynamically scheduled generation internal to the CONTROL AREA (NATIVE CONTROL AREA).

NI_{SDSLE} = sum of dynamically scheduled load external to the CONTROL AREA (ATTAINING CONTROL AREA).

NI_{SRSE} = ~~sum of dynamically scheduled~~ SUPPLEMENTAL REGULATION SERVICE external to the CONTROL AREA (CONTROL AREA purchasing the SUPPLEMENTAL REGULATION SERVICE).

NI_{SRSI} = ~~sum of dynamically scheduled~~ SUPPLEMENTAL REGULATION SERVICE internal to the control area (CONTROL AREA selling the SUPPLEMENTAL REGULATION SERVICE)

and where SUPPLEMENTAL REGULATION SERVICE for an overgeneration condition is assumed to be negative and for undergeneration it is positive to achieve the desired effect via NI_S on ACE as described in Operating Manual, Appendix 1A, Subsection C – "The Area Control Error (ACE) Equation"

Item 5. Dynamic Scheduling Problems – Monroe Landrum

Background

Two items related to dynamic transfers have been identified. Monroe Landrum will lead the discussion on these items.

Attachments

5a1 John Calder email

5a2 Garth Arnott email

From: Landrum, Monroe J., Jr. [MJLANDRU@southernco.com]
Sent: Tuesday, April 13, 2004 4:08 PM
To: Gordon Scott
Subject: FW: Dynamic Schedules

I just wanted to see if there were any other concerns about template P3T3. Looks like I got my answer. At least I am better able to address the IS.

Take care,
Monroe Landrum

-----Original Message-----
From: Dison, Joel
Sent: Tuesday, April 13, 2004 14:35
To: 'Lewis, Wayne'; Landrum, Monroe J., Jr.; John_Calder@dom.com
Cc: tiswg@nerc.com
Subject: RE: Dynamic Schedules

Any standard that requires a dynamic schedule tag to be changed frequently is not a "reasonable" standard. The goal is to make sure the information in the IDC is correct. The goal should not be to burden the industry with additional responsibilities. As written, the existing Policy is exactly that - a burden... More than that, it is a burden that doesn't accomplish what it should. It ignores large errors caused inherently by large dynamic schedules and burdens administrators of small dynamic schedules with frequent changes that have very little, if any, impact on overall accuracy of the IDC.

Joel Dison Manager, Market Policy
Southern Company Generation and Energy Marketing
Tel: 205-257-6481 Cell: 205-283-8559

-----Original Message-----
From: Lewis, Wayne [mailto:Wayne.Lewis@pgnmail.com]
Sent: Tuesday, April 13, 2004 2:28 PM
To: Landrum, Monroe J., Jr.; John_Calder@dom.com
Cc: tiswg@nerc.com
Subject: RE: Dynamic Schedules

This email was sent to the tiswg List Serve

I think we should not worry at this time that someone will intentionally make multiple low MW tags to avoid updating their tags in the IDC. Let's make the standard reasonable and then wait to see if we need to fix that loophole. Remember the 80/20 rule.

Wayne.

-----Original Message-----
From: Landrum, Monroe J., Jr. [mailto:MJLANDRU@southernco.com]
Sent: Tuesday, April 13, 2004 2:41 PM
To: John_Calder@dom.com
Cc: tiswg@nerc.com
Subject: RE: Dynamic Schedules

This email was sent to the tiswg List Serve

John, I have not overlooked your email. I have just been trying to

develop some options for the IS to consider.
The IS will be meeting next week. Part of their agenda is to address this very issue. There appears to be a lot of concern in the southeast over the template of tagging/adjusting dynamic schedules.

Another thing to consider is aggregating your loads in another CA, that utilize a common interface, into one tag. If this still doesn't help your situation, then your suggestion of adjusting tags if they deviate by +/-25% or 15MW (whichever is larger) could be applied as long as we aggregate the dynamic schedules on each interface of the CA. Another option is the one that you suggested about limiting the number of dynamic tags (2) allowed to serve a given load. I am not sure that NERC can enforce this limitation.

Monroe Landrum

-----Original Message-----
From: John_Calder@dom.com [mailto:John_Calder@dom.com]
Sent: Thursday, April 08, 2004 06:19
To: Landrum, Monroe J., Jr.
Cc: tiswg@nerc.com
Subject: Dynamic Schedules

Monroe,

With the issuance of the new compliance templates, specifically P3T4, there
has been much discussion between us and neighboring control areas about how
we will comply with dynamic schedules. For example, Dominion has a load that is telemetered to our EMS, but physically exists in CPLE, whose EMS also gets the telemetered value. The load is normally 2MW but, on winter
mornings, in the space of an hour, can easily go to 4 or more MW.

If the load is tagged at 2MW, anytime the integrated value exceeds 2.51, an
adjustment for this tag has to be entered to 3MW. Then when it gets to 3.75, it has to be adjusted to 4. Likewise, on the way down.

Dominion is also looking at implementing a retail pilot which could result
in 1 MW schedules.

Although this 25% rule is not a change to Policy, holding the LCA responsible is new. And the edict has come down that we will be compliant.
One of the methods being kicked around (this is NOT my idea) is to automate the generation of tags such that every 2 - 5 minutes for every dynamic schedule, an adjust is issued. If everyone did this, I think this
would quickly overload the etagging system and probably the IDC also. And
for small, varying loads, I don't know that there are any good solutions.

There was also some discussion about what happens if you have a dynamic tag
whose integrated value changes during the hour and an adjust is issued to
cover the change and, because of timing and a TLR somewhere, the adjust gets held. Are the CAs supposed to go into their EMSs and,

simultaneously,
deactivate the load signal and freeze it at the tagged value +/- 25%?
Meanwhile the load gets hit with imbalance charges?

Without modifications, attempting to comply with this template has the real
possibility of causing more harm than good. I fully understand and support
the intent of the policy and compliance template when it concerns large
dynamic schedules. I would like to see a threshold put on dynamic
schedules such that tags have to be adjusted if the schedule deviates from
the tag by +/- 25% or +/- 15MW (whichever is larger). I have been told
that putting a threshold on dynamic schedules was suggested to NERC's
compliance committee, but was rejected out-of-hand with the assumption
being that if a 15 MW threshold was instituted that an LSE with a dynamic
load of 1500MW would supply this load with 100 dynamic tags of 15MW each.
I don't know how other CAs/LSEs handle dynamic schedules, but could we
resolve the compliance committee's fear about multiple tags by saying any
metered load may have, at the most, up to 2 dynamic schedules serving that
load?

Please let me know if we can (or want to) recommend that IS take a
proactive approach to resolving this problem, or if we have to wait for the
system to break before we can suggest a fix.

Thanks

John Calder
Dominion Virginia Power

Subject: Dynamic Schedule Loading levels in IDC

The current system of populating IDC with loading level of dynamic schedules is not working effectively, equitably or accurately. The data is currently sent to the IDC via a tag. The current NERC policy requires the tag be adjusted should the dynamic flow vary from the tag by greater than 25%, this leads to numerous adjustments to the tag, dynamic schedules being held or curtailed and larger schedules being allowed much larger absolute variances between tag and flow.

Dynamic flows are typically the marginal resource on a system consequently their magnitude varies with errors in load forecast, unit contingences, schedule curtailments and system constraints. Because of the above reasons the dynamic flows vary widely and frequently. This leads to inaccurate information being reported to the IDC and consequently IDC incorrectly calculating available control actions. A second problem is dynamic transactions are being curtailed or held due to incorrect tags or tagging timing issues. The final problem is the workload the numerous tag changes create. Currently a 1000 mw dynamic schedule can have 250 mw of untagged flow on the system, something that should be concern everyone, conversely a 10 mw dynamic schedule is judged to be out of range if tagged to flow is off by 3 mw, a level that is noise on the system.

A solution that will improve the accuracy of the IDC and enhance reliability of the bulk electric system is to populate IDC with real time flow and transmission priority of all dynamic schedules. This will give IDC the same level of accuracy it receives of all other dynamic elements necessary to calculate. This could be accomplished through the RCIS, a system already in place and used to bring back other dynamic elements. There may be other means that are more suitable.

Garth Arnott
garth.arnott@ncemcs.com
919-875-3025
919-218-5489 cell

Item 6. AIE – E-Tag – EMS Survey and Dynamic Transfer Catalog – Gordon Scott

Background

The subcommittee agreed to survey those entities that had differences between AIE and NSI data for the seven hours surrounding the August 14 blackout. The subcommittee plans to issue this survey and expects that **all interchange** be accounted for and the control area should use any data available to make this determination, e.g., comparing EMS data to E-Tag data. The survey responses should also provide a detailed explanation of how the control areas account for dynamic transfers.

Gordon Scott will lead the discussion on next steps in the survey process.

Attachments

6a1 Draft Survey letter to the industry

6a2 Attachment A to Survey Letter

Background and Action

The subcommittee should draft a letter to the industry describing the requirements for submitting data for the Dynamic Transfer Catalog. Bob Cummings will lead the discussion on this important project that was approved by the Operating Committee.

Attachment 6a1

(GLS Note: Check with Bob, Joe, and compliance to see what data was submitted to the outage, and see what questions were asked on the outage questionnaires.)

AIE – E-Tag Audit Report and Follow-up EMS Survey

This letter is to inform you that the Interchange Subcommittee is requiring detailed clarification for data submitted from your control area to the AIE – E-Tag audit for August 14, 2004. The Interchange Subcommittee believes that the "explanations" submitted to NERC by the Control Areas to NERC's February 4, 2004 letter are inadequate, and do not contain sufficient detail to determine why the differences between AIE and NSI data exist. The Interchange Subcommittee has included an attachment that will provide guidance for the further submission of data. This Attachment A is a guide and may not address the precise items needed for a "clear and unambiguous" explanation of scenarios associated with your control areas interchange.

The Interchange Subcommittee wants to ensure that this request for data is explicit and unequivocal. The subcommittee expects the submitted data to fully characterize each transaction, and the subcommittee should not have to return to the company with a follow-up on this data requesting further explanation.

The Interchange Subcommittee requires the responses to this survey be submitted by __________. The subcommittee will allow an extension to the response till __________ by request. If you cannot meet these deadlines you must inform the subcommittee by ___________.

Background

On March 24, 2004 the Operating Committee approved Version 1 of the Dynamic Transfer White Paper and the development of a Dynamic Transfer Catalog. The white paper was approved as a reference document. The document will be used for guidance in the development of a DT Catalog. The catalog will be a major project for the industry, the Interchange Subcommittee and other Operating Committee subcommittees.

The DT Catalog will identify the control area configurations for dynamic transfers implemented to accommodate jointly owned units, remote loads, remote generation, supplemental regulation service, and AGC interchange, among other uses. The control areas will be required to provide detailed operating and accounting methods for each dynamic transfer along with the 'associated' control area(s) involved in the dynamic transfer. The Interchange Subcommittee will review the data to ensure among other items that:

- Entities are accounting for transfers of the same MW in the same way
- Transfers are handled correctly in the ACE equations
- Transfers that should be tagged are tagged.

AIE - E-Tag Audit

On _______ the Resources Subcommittee requested an AIE – E-Tag audit for data surrounding seven hours of the August 14, 2003 outage. The AIE - E-Tag audits compared the net E-Tag schedules to the net scheduled interchange from the AIE surveys. Although the audits did not compare exact sets of data, it was assumed that the numbers would be in the same range. The audit was requested to diagnose frequency excursions, identify root causes, and determine adverse frequency trends in the Eastern Interconnection.

There were about 30 control areas that averaged 100 MWs of difference over the seven survey hours, and several control area differences were well over 1,000 MWs. The Unfortunately, some control areas did not provide the information needed, and others supplied data that needs explanations or clarification. The incomplete results demonstrate that some dynamic schedules were not tagged or re-tagged properly.
Based on these results, a second request to clarify the two sets of data was submitted on February 4, 2004, “Request for Control Area Data.” Control areas were asked to categorize their untagged schedules. The responses fell into the following categories:

1. Dynamic schedules/pseudo ties
2. Losses
3. DC ties
4. Other (pass throughs, meter error, rounding error, etc.)

Again the data submitted was not, in most cases, detailed or clear enough to allow the Interchange Subcommittee to determine if the transactions was required to be Tagged according to Policy 3. The responses also point to the need to understand the operating and accounting characteristics for the various scenarios of dynamic transfers.

END

Attachment 6a2

Attachment A for EMS Survey

Comments to the AIE – E-Tag audit stressed that comparing these numbers (AIE to NSI) will be inherently mismatched. This survey is not simply asking control areas to explain the differences between AIE and NSI. The subcommittee expects an accounting for all interchange; therefore, the control areas should use any data available to make this determination e.g., comparing EMS data to E-Tag data. The survey responses should also provide a detailed explanation of how the control area(s) account for dynamic transfers. The control area must state for each transaction (see spreadsheet):

- Classify the type of transaction
- Are you the sink or source for the transaction (or other)?
- Was the transaction Tagged?
- If not Tagged, what exempted the transaction from being Tagged?
- Is the “other” control area accounting for the transaction in the same manner you are?
-
-

Transaction Type	MWs	Source / Sink	Tagged Yes /No	Tag Exemption	Accounting

Attachment B for EMS Survey

The following control areas are required to provide responses to the survey.
[Joe Emde will provide.]

Item 7. The Interchange Authority Function – John Simonelli

Background

Note: Please see agenda Item 6 of the August 21, 2004 Interchange Standards and Business Practice meeting for background and attachments for this agenda item. Discussion on these items will be a continuation from the April 21 meeting.

John Simonelli will lead the discussion on the IA Function.

Roman Carter will lead the discussion on Interchange State definitions.

Al Boesch will lead the discussion on an Operating Authority Users Manual

Item 8. IDC Granularity – Lanny Nickell

Background

Lanny Nickell from the ICD Granularity Task Force will lead the discussion. The group is considering a white paper on congestion management. The subcommittee should review the options proposed in the paper and provide comments to the task force.

Attachment

8a White Paper on the Future of Congestion Management, Version 2.0

White Paper

On the

Future of Congestion Management

Version 2.0

April 2004

DRAFT 2.0

Prepared by the

IDC Granularity Task Force

of the

North American Electric Reliability Council

Table of Contents

EXECUTIVE SUMMARY

Experience has shown that the current Transmission Loading Relief (TLR) Procedure often takes a significant amount of time to implement. Further, because the TLR process relies on curtailment of transactions as an ineffective proxy for ordering generation redispatch, significant amounts of transactions have to be interrupted to provide the necessary relief. The events of August 14, 2003, show that the time taken to effect relief on transmission elements can be crucial to the reliability of the system.

The IDCGTF feels that the existing IDC will not sufficiently serve the needs of the electric utility industry in the future without a significant overhaul.

The IDC Granularity Task Force (IDCGTF) presents three options for consideration by the electric power industry for the long-term vision of congestion management.

Option 1 would modify the IDC to evaluate the impacts of interchange transactions using the same level of granularity, at least, that is used by Transmission Providers to evaluate transmission service requests. Option 1 does not address all of the problems facing the IDC, such as the need to incorporate comparable treatment of counter-flows on Flowgates. But the IDCGTF does believe Option 1 provides some improvement in granularity and could be implemented fairly quickly. Option 1 could be implemented as a stand-alone change or as an intermediate step toward Options 2 or 3.

Option 2 continues to utilize the tagging and modeling granularity described in Option 1, but changes how responsibilities to achieve relief are calculated and assigned. Internal and External Relief Responsibilities (IRR/ERR) would be calculated, as detailed in Appendix A of this paper, for each Balancing Authority[1]. or Control Area Under Option 2, fulfillment of these responsibilities associated with transactional impacts would still be accomplished primarily through the curtailment of tagged transactions, and the curtailments would continue to respect current transmission service priorities. As a backstop for those curtailments, a set of recommended generation dispatch changes can be generated for immediate relief if tagging curtailments are ineffective or take too long to accomplish. However, in its investigations, the IDCGTF concluded that the Option 2 relief prescription process, and complex coordination issues, may make Option 2 difficult to implement.

Option 3 is a progression of the development of Option 2, using the assignment of responsibility for relief, but would differ in the actions taken to achieve necessary relief. Option 3 would depend on the RCs to identify and initiate effective and efficient generation dispatch changes to achieve the required relief instead of curtailment of individual transactions. Option 3 builds on the concepts of Option 2 and can go beyond to address other issues associated with timely congestion management and inadvertent interchange. Option 3 can be adapted in various ways to work with the new market structures. However, the effort to adopt Option 3 will require a coordinated acceptance by the industry, and will require rigorous technical and business practice scrutiny.

Option 3 can be implemented at various technical levels. For example, Option 3 could be implemented without the incorporation of real-time data. The real-time data would help refine the ERR/IRR calculation and help RC's with redispatch choices. However, with improved SDX reporting and merit order incorporation, the ERR/IRR calculations can be refined to an acceptable level, and RC's have other sources of referencing real-time data to verify unit outputs and flows. In summary, Option 3 may be

1For purposes of this white paper, the electrical boundary under a Balancing Authority's purview may be either that of an existing Control Area or the boundary encompassing a market footprint, as applicable.

technically implemented within 1 to 3 years. Policy and legal filing issues may be the critical path in implementing Option 3.

Recommendation

The IDC Granularity Task Force recommends that the NERC Operating Reliability Subcommittee adopt and implement Option 1 immediately and that Option 3 be adopted and implemented as the preferred long-term strategy for the IDC.

The IDCGTF further recommends that the NERC Operating Reliability Subcommittee expedite the formation of appropriate teams to develop the business case for implementation of these options. The Task Force also requests that the NERC incorporate the views of other NERC committees, NAESB, and appropriate regulatory bodies to support the proposal.

INTRODUCTION

The IDCGTF was originally formed by the Security Coordinator Subcommittee (now Operating Reliability Subcommittee) to investigate and propose technical solutions to existing inaccuracies in the way the NERC Interchange Distribution Calculator (IDC) determines the impacts of energy transactions on Flowgates. The existing IDC inaccuracies are generally due to lack of precise information given to and/or used by the IDC regarding which generator or generators should be dispatched in the IDC model to accurately reflect the true impacts of a particular transaction being scheduled. The lack of precise information is generally referred to as a lack of "granularity". This white paper proposes a method by which ultimate granularity could be implemented in the IDC to evaluate impacts of transactions and appropriate required relief to responsible parties during a TLR event.

Problem Statement

The bulk electric system is changing from being dispatched on a Control Area basis to being dispatched on a balancing market basis. That is, the responsibilities to balance load and generation and to preserve frequency that now lie with over 100 independent Control Areas in the Eastern Interconnection are being or have been transitioned to fewer, larger balancing markets facilitated by RTOs or ISOs. These larger balancing markets are not being, nor are they likely to be, implemented at the same time. In other words, some Control Areas will be part of a larger market while others are not. The actions of these markets to balance supply and demand over a broad geographic area utilizing a centralized economic dispatch will change the congestion patterns throughout the Eastern Interconnection. In order to be effective, the future IDC will need to transition to address market seams issues while continuing to incorporate traditional interchange transactions.

The current NERC IDC is founded on the concept of Control Area to Control Area transactions. It assumes linear, reciprocal responses for the source and sink Control Areas. It doesn't correctly account for movement of specific generators scheduled separately or as part of a central economic dispatch within Control Areas and larger balancing markets. These potentially incorrect proxy assumptions become more obvious and problematic when large numbers of Control Areas are subsumed into a few large balancing markets.

The problems facing the IDC are many and include:

1. The current case-by-case review and specific solutions to granularity problems do not result in **consistent and global application of a comparable granularity criterion**, and require significant effort to implement and maintain each special case.
2. The IDC does not currently **recognize and address the true impacts of evolving market** dispatch and other point-to-point energy transactions occurring between, into, out of, and around Control Areas. That results in growingly imprecise and, sometimes, ineffective congestion management under the TLR process.
3. The current IDC does not yet **incorporate counter-flows** as directed by the NERC Operating Reliability Subcommittee (ORS) in June 2001, based on NERC Parallel Flow Task Force (PFTF) recommendations.
4. **Continued need for increasing reliability and ability to address response time for IORLs**. The current IDC is only an intermediate term next-hour congestion management tool. NERC needs a larger voice in development of a toolset that can be used to address the 30-minute window for resolution of IROLs.
5. Since its inception, there has been a recognized **need to incorporate real time data in the IDC.** The unit participation for NNL and TDFs within the IDC use seasonal case

assumptions, which can produce less than accurate results. The completion of CO-114 incorporates some real-time data aspects for the markets that will use those features, however, the remaining CAs continue to use the less than perfect seasonal assumptions.

6. There is always a need to increase efforts to **"keep the lights on."** Any curtailments whether non-firm or firm have the potential to effect the curtailment of load. Declaring TLRs can limit (in conjunction with limited AFC's) most or all import directions making it difficult to import power. Tag curtailments can lead to an increased use of EEAs to import power. In doing so, there is an increased risk that firm or non-firm curtailments may result in curtailment of actual load.

Background – How the IDC Works Today[2]

Currently the IDC calculates Transaction Distribution Factors (TDFs) on a Control Area to Control Area basis. A TDF represents the impact of an Interchange Transaction on a given Flowgate. The IDC uses the Sending Control Area and Receiving Control Area information indicated on a tag and an associated TDF to determine if that Interchange Transaction affects a specific Flowgate. During TLR, those Interchange Transactions having a 5% or greater TDF on the Flowgate are subject to curtailment.

Currently, source and sink information that indicates the dispatch of specific generators within a Control Area are not generally used for TDF calculation. However, some pseudo control areas are recognized by the IDC to address specific known granularity problems, and the PJM-MISO congestion management process is expected to utilize marginal zones for determining transactional impacts into and out of their market footprints.

The IDC calculates TDFs by increasing on-line generation in the Source Control Area and decreasing on-line generation in the Sink Control Area such that the net Control Area change is 1 MW. In general, the amount that a particular unit participates in a transaction is based on the ratio of the capacity of that unit to the total generating capacity of the units within the Control Area. If a unit is off-line or has been identified by the Reliability Coordinator as a non-participating unit, its capacity it set to zero. The generator participation for a Control Area is the same for both imports and exports. It is important to note that, with this method, intra-Control Area transactions will have a TDF that nets to zero for all Flowgates.

2 IDC Change Order 114, which implements the PJM-MISO congestion management system for their market expansions, proposes to change the manner in which some of the IDC calculations are performed.

PHILOSOPHY OF A SOLUTION

Since its inception, the use of control areas as the level of granularity in the IDC has been a compromise. It has always been recognized that better impact results could be calculated if the individual source generators and ultimate load zones of each transaction were known and could be used in the calculation. Unfortunately, since Interchange transactions are scheduled between control areas, tagging itself was somewhat limited in identifying sources and sinks at that level of granularity. Now, as markets are expanding and control areas continue to merge and become larger, these shortcomings of the existing system are getting worse. It is apparent that there should be an initiative to improve the granularity of the impact calculations for the Eastern Interconnection.

The use of self-calculated market and dispatch impacts proposed by the expansions of the PJM and MISO markets improves the granularity of the impact calculations for the footprints and areas of direct observability of both markets, but does nothing to improve the impact calculations of larger non market-based control areas. Since not all transmission systems are FERC jurisdictional, and not all control areas will be within ISOs or RTOs, a more universal solution is needed.

The problem of how to best to calculate the impacts of transactional flows and curtailment actions for use in TLR must be dealt with on three objective levels: focus on reliability, focus on economic aspects, and focus on equity issues.

- High focus on reliability for loading relief would trend toward a solution that would be very prescriptive, calling for the movement of specific generators to achieve the greatest amount of relief in the shortest amount of time, regardless of cost.
- High focus on an equitable solution would appropriately recognize transmission service priorities in the assignment of relief responsibility to each market participant and would give options for how Control Areas achieves relief requirements. This would not be the quickest because it requires the most coordination.
- High focus on the economic aspects would implement a security-constrained economic dispatch over entire interconnection. This would require exchanging economic information on generation and interchange transactions.

The solution should improve reliability, maintain equity, and result in cost savings to the industry.

OPTIONS FOR IMPROVING GRANULARITY AND CONGESTION MANAGEMENT

The IDCGTF has considered many options for improving IDC granularity and congestion management. In October 2002, the IDCGTF presented six exploratory approaches to the NERC ORS. Two of the six were recommended, and the ORS provided direction for expansion of one method that is the basis for some of the congestion management proposals within this paper. In December 2002, the IDCGTF presented further advanced descriptions of the chosen approach.

The following section will describe three development options for improved congestion management. These options vary in complexity, paradigm shift, and difficulty of implementation. These options may all be developed and implemented in a phased approach. Alternatively, any specific one or more may be developed and implemented on a stand-alone basis. Depending on the method adopted, future congestion management tools may or may not be developed as an extension of the IDC. Options 2 and 3 incorporate the techniques previously presented to the NERC ORS, and represent a major re-thinking of the congestion management process. Since these options may take some time to implement, another fallback option (Option 1) is described to further advance along the lines of the existing IDC concept of transaction-based curtailments.

The three developmental options include some common recommendations. All 3 options will need improved SDX reporting, some knowledge of unit merit order, and eventual incorporation of real time data. All 3 options will require varying amounts of policy and legal filings in addition to various technical hurdles.

Option 1

The first option provides increased granularity in the IDC by incorporating zones that are being used by Transmission Providers in evaluation of transmission service requests. It also improves the accuracy of NNL calculations by using block loading order data submitted by each Control Area. The changes to tagging and the IDC required to implement this option are relatively minor and may be implemented in part or in whole within one year.

Option 2

The second option changes the way relief responsibilities are assigned. This technique first requires the calculation of relief responsibility for each Control Area or Balancing Authority. In this option, the distributed impacts of a BA's net interchange as well as the impacts of serving load within the BA's boundaries are determined and relief responsibilities are assigned to each BA accordingly. Once a relief responsibility is determined and assigned to a BA, it may achieve the required relief by either curtailing transactions or redispatching. The impacts of curtailed transactions are calculated using the zonal modeling incorporated in the first option. This option relies on significant real-time data, will require IDC software changes and significant training. As such, this option is expected to be more costly and require more time to implement than the first option. However, the increased real-time data and changes to how relief responsibilities are determined should increase calculation accuracy and more appropriately determine the real contributions to congestion.

Option 3

The third option not only changes the way relief responsibilities are assigned but also changes the mechanism in which the relief is achieved. In this option, the relief responsibilities are allocated in a manner similar to that of the second option. The control actions, however, are taken by the Reliability Coordinators who are in the best position of achieving the most effective and efficient means of relief through redispatch. Those BAs to whom relief responsibilities are assigned would be responsible for financially compensating the operating entity or entities performing the redispatch. Option 3 would require development of mandatory financial compensation mechanisms and any associated tariff changes. Similar to Option 2, to be most effective, Option 3 relies on significant real-time data in addition to some additional unit availability data requirements. However, the increased real-time data, changes to how relief responsibilities are determined, and improvements in relief mechanisms should increase calculation accuracy, more appropriately determine the real contributions to congestion, and effectively and efficiently achieve expected relief. Various aspects of Option 3 are not significantly complex and could be implemented within a reasonable amount of time. Other features such as incorporation of real-time data could take a longer period of time to technically implement.

Option 3 provides a long-term congestion management process that accomplishes the white paper objectives and provides flexibility for expanded features beyond the white paper objectives.

OPTION 1

Today, the level of granularity used to determine the impacts of transmission service when it is reserved is in many cases different from the granularity used to determine the impacts of the same transmission service when it is scheduled and curtailed. Many Transmission Providers, utilizing a FERC approved methodology filed in their OATTs, evaluate requests for transmission service by dispatching specific generators or groups of generators identified as the source or sink within a Control Area. However, with few exceptions, the IDC evaluates the impacts of interchange transactions by primarily dispatching seasonal on-line generation within a source or sink Control Area. Option 1 recommends that the IDC evaluate the impacts of interchange transactions using the same level of granularity being used by Transmission Providers to evaluate transmission service requests.

Zones Modeled in IDC

In this option, Control Areas or Balancing Authorities currently modeled in the IDC would continue to exist. However, additional zones modeled within the existing Control Areas or Balancing Authorities would be created. The criteria for development of these zones in the IDC model are:

- Must represent those zones used by Transmission Providers in their transmission evaluation processes.
- Must ensure that these zones are properly linked to those used as source/sink zones in tagging.
- A generator zone must contain one or more generators.
- A load only zone must contain a meterable load pocket.
- Zonal participation factors and block loading merit order must be provided for zones that contain more than one generator.
- A Control Area may contain one or more zones.
- Zones cannot cross Control Area boundaries.

The addition of zones within the IDC model will allow the IDC to calculate zonal TDFs in addition to the Control Area TDFs already calculated today. The impacts of interchange transactions can then be more accurately determined using the applicable TDFs reflective of the Sources and Sinks identified on tags.

Transmission Providers are responsible for filing their ATC calculation processes with FERC and FERC is ultimately responsible for ensuring that equitable and comparable practices are being administered by the Transmission Providers. However, NERC does need to assess the reliability impacts of how the Transmission Providers define and utilize zones in their transmission service evaluation processes. As a result, each Transmission Provider should file their ATC methodologies and transmission service evaluation processes with NERC for review and approval from a reliability perspective. It is suggested that the ORS be the appropriate body to perform this review. The NERC ORS would need to develop a set of criteria so that approval is not subjective. If the ORS provides a favorable review of a Transmission Provider's methodology, then that provider's zones would be added to the IDC model. An unfavorable review would require the provider to make appropriate adjustments to its methodology before being allowed to add its zones to the IDC model.

Any review of a Transmission Provider's transmission evaluation methodology should consider the following principals for reliability:

- Should verify that sources and sinks on the schedule match those identified on the reservation.
- Should verify that sources and sinks on the schedule can be dispatched as scheduled.
- Should ensure that source and sink generators associated with curtailed schedules will be the ones re-dispatched.

This option will continue to maintain Control Area modeling in the IDC for purposes of NNL calculations. However, this option proposes to improve the accuracy of NNL calculations by using block loading order data submitted by each Control Area. This will enable the IDC to determine a more accurate dispatch of generation to be modeled as serving network and native load.

Option 1 could further evolve to incorporate the benefits of real-time data. The IDC next hour calculations would then utilize real-time data complimented by the dispatch block loading of generation.

Tagging Granularity

To accommodate the level of granularity being used by Transmission Providers in their evaluation of transmission service requests, Transmission Providers would be required to register their Sources and Sinks in the TSIN registry. Since Transmission Providers are currently only required to register their PORs and PODs, the TSIN registry would have to be modified. Included in the registration of these Sources and Sinks would be an identification of generation (using IDC bus names) associated with each Source or Sink and a mapping of Sources/Sinks to Sources and Sinks currently registered for tagging purposes. Each Transmission Provider would only be allowed to register Sources and Sinks that represent generators or loads within their transmission footprint.

Implementing the granularity proposal described above would not require PSEs to do anything differently than they do today from a tagging perspective; E-tagging already supports the use of Sources and Sinks. Further, PSEs would have no additional requirements to register additional data on TSIN. PSEs could continue to use their Sources and Sinks already registered. The IDC would simply be modified to evaluate tags based on the Source and Sink in the IDC model that is mapped to the Source and Sink identified on the tag.

Pros

The following items are considered to be strengths of Option 1.

- Will not require extensive changes to the existing IDC.
- Introduces improved granularity to the IDC.
- Can be implemented in reasonable amount of time.
- FERC ensures comparability within zone definitions.
- Schedules are curtailed in the same manner in which transmission service is provided.
- The process is manageable. It all starts with the TSIN registry.

Cons

The following items are considered to be potential drawbacks of Option 1 or items requiring significant effort to implement. Granularity is not globally uniform across all TPs due to differences in ATC/AFC methodologies.

- NERC would have to review transmission providers' evaluation processes.
- Perpetuates the myth of contract path flow-ability.
- Does not incorporate the effects of counter-flows for NNL or tags.

Data Requirements

- Block loading merit order and participation factors for all generators in each zone, at least once per day via SDX.
- OASIS sources and sinks registered by TPs and linked to sources and sinks already registered by PSEs.
- The NERC DFWG must change IDC Models to incorporate TP's zonal granularity.

- IDC software changes would have to be done to handle additional zones, PORs/PODs, and submission of associated data via SDX.
- Eventual incorporation of Real-Time data.

OPTION 2

Option 2 continues to utilize the tagging and modeling granularity described in Option 1, but changes how responsibilities to achieve relief are calculated and assigned. These relief responsibilities will be calculated for each BA as described in an Appendix A of this white paper. Under Option 2, fulfillment of these responsibilities associated with transactional impacts would still be accomplished primarily through the curtailment of tagged transactions. The transaction curtailments would continue to respect current transmission service priorities. As a backstop for those curtailments, a set of recommended generation dispatch changes can be generated for immediate relief if tagging curtailments are ineffective or take too long to accomplish.

Assignment of Relief Responsibility

The IDC must determine each Balancing Authority's net interchange based on tags. This is subtracted from the net actual interchange determined from real-time data. If the resultant is greater than zero, it is treated as net interchange at the lowest priority. The IDC will calculate ERR for each area based on this untagged net interchange. Any Balancing Authority with an ERR based on this calculation will be expected to curtail its untagged interchange. If curtailment of this ERR is sufficient to achieve the necessary relief, no further action is needed. Otherwise, the net interchange based on tags at each a priority level will be determined and used to calculate each Balancing Authority's ERR.

Each Balancing Authority with an ERR could achieve its responsibility via curtailment of tagged transactions. If no tagged transactions are available for curtailment to a Balancing Authority that has an ERR, that Balancing Authority would have to find other means of achieving the relief required. The IDCGTF has concerns that this process for relief may not identify and initiate relief actions in a timely fashion.

Issues

The following Option 2 items may be addressed in this White Paper, but are expected to be issues that will need further group discussion at various NERC committee levels:

- Curtailments based on TDFs could result in considerable mismatch with the ERRs assigned.
- Coordination issues may slow the implementation of curtailments.

Pros

The following items are considered to be strengths of Option 2:

- IDC curtailment algorithm remains the same.
- Introduces improved granularity to the IDC.
- TP zonal methods must be approved as reliable through NERC review process.
- Complements the PJM-MISO market system changes.
- Significantly reduces the amount of transactions being curtailed.

Cons

The following Option 2 items are considered to be potential drawbacks or items requiring significant effort to implement. The time needed to coordinate curtailments between transaction participants may make it impractical.

- ERRs for remote BAs/CAs could result.
- There may prove to be an imbalance between the relief provided by tag curtailments and the ERRs assigned. A BA may be assigned an ERR without an immediately obvious way of

achieving it because the BA's tags have no direct impact on the Flowgate. Potentially, tagging curtailments could provide all of the expected relief before a BA's ERR is fulfilled.

- Not uniform across all TPs due to differences in ATC/AFC methodologies.
- Perpetuates the myth of contract path flow-ability.
- It may be difficult to prescribe tag curtailments and BA internal redispatch that will not over-shoot the total relief responsibility of some BAs.
- In order to allow for BA choices in prescriptive relief, an additional higher level of coordination will need to occur between BAS (and RCs). Even so, the complexity of coordination may be infeasible within the time period currently used to arrange tag curtailments. Additional coordination may also lead to increased 24/7 staffing levels.

Data Requirements

- Block loading merit order and participation factors for all generators in each zone, at least once per day via SDX.
- OASIS sources and sinks registered by TPs and linked to sources and sinks already registered by PSEs.
- The NERC DFWG must change IDC Models to incorporate TP's zonal granularity.
- IDC software changes would have to be done to handle additional zones, PORs/PODs, and submission of associated data via SDX.
- Real-time and projected output for all generators.
- Total real-time and projected demand for each Balancing Authority.
- ACE data for each Balancing Authority as a future refinement.

OPTION 3

Like Option 2, Option 3 would use the IRR/ERR methodology, described in Appendix A of this white paper, for assigning responsibility for relief, but would differ in the actions taken to achieve necessary relief. Option 3 would depend on the RCs to identify and initiate effective and efficient generation dispatch changes to achieve the required relief instead of curtailment of individual transactions.

A settlement process would charge the BAs based upon their assigned IRR/ERR contribution to compensate for the generation redispatch. To avoid pricing improprieties by generators for this service, a price cap or auditable cost plus system would have to be in place. Development of such a settlement system is a business practice that should be developed by the NERC MC or NAESB.

As part of the advanced development of Option 3, a new toolset would be established for Reliability Coordinators to help them identify the best redispatch options. The new toolset would replace the IDC prescribed curtailment process, but would utilize much of the same linear analysis, and also incorporate real time ICCP data, utilize merit order knowledge, and link to pricing and bidding processes. The new toolset could also perform functions that help Reliability Coordinators communicate information needed for making sound coordinated redispatch decisions. In its initial stages of implementation, Option 3 could take on simpler features that may require that each RC have pre-established and known dispatch pairs to alleviate overloads on each Flowgate in their purview.

Implementation of Option 3

The basis for proposing a long-term solution of direct redispatch with financial resolution is that it will provide effective, economical, and timely mitigation of IROL/SOL violations. Unlike some of the other approaches considered, this method also has potential to provide a pricing signal that can be a check and balance for needed improvements in a number of systems in need of monitoring and compliance such as full tagging (tagging vs net scheduled interchange), updating tagging of dynamic schedules, and energy imbalance.

As part of Option 3, the Reliability Coordinators issuing a TLR will cooperate with other Reliability Coordinators to determine an effective and economical redispatch to mitigate the operating limit. The RC will initiate the redispatch on behalf of the Transmission Provider.

In order to ensure that redispatch costs are recovered, BAs shall be required to compensate the redispatch service provider for their share (including carrying charges) of the redispatch costs according to the IDCGTF proposed ERR/IRR flow responsibility calculation. In order to emphasize the local responsibility for the Flowgate, the system could be established whereby the “host” Control Area where the Flowgate resides assumes a direct assignment percentage of a limited portion of the redispatch costs, with the remainder socialized using the ERR and IRR formulation. An additional consideration would be to include the additional impact used by a BA during an EEA as a directly assigned cost. Each BA will determine its own internal allocation of costs to Network Integration Transmission Service and Point-to-Point customers. Each BA would determine and document the method by which redispatch costs are recovered. Allocation of costs may recognize differences in costs assigned at each TLR level.

Generators would provide information for posting regarding the availability of generation or load shedding capability and bid prices. The RC would post the information electronically on a real-time basis. The owners bid prices may involve either the price for increasing or decreasing the output of generating units.

Type of redispatch that could be implemented

Redispatch is often thought of as coordinated movement of a pair of generators, however, redispatch could take one of the following forms.

- Identify increment/decrement generation pairs.
- Identify beneficial impacts of Increment units that can be off-set with decrement from various locations (individual units or external sales)
- Identify beneficial impacts of Decrement units that can be off-set with increments from various locations (individual units or external purchases)
- Complex redispatch combinations involving multiple units across multiple Flowgates. Tools may need to be established to help determine redispatch.
- Redispatch pricing signals could be used to incorporate voluntary load curtailments into the redispatch strategy.
- In the event that involuntary load curtailment, pricing caps could be used to compensate for load curtailed.

Redispatch Considerations

Redispatch would be performed with the intent of minimizing costs subject to the following considerations:

- Minimized cost to the extent practicable to effectively relieve the constraint.
- Consideration of complexity – moving minimal number of units.
- Start-up time and ramping capabilities
- Expected duration of high Flowgate loading.
- Anticipate minimum run levels and minimum run time arrangements.
- Review of the effect of redispatch on next contingency analysis.

As such, redispatch required on short notice may utilize redispatch that tends to be quickly rampable and convenient, while redispatch in later hours of a TLR may look for a more cost effective redispatch combination.

Issues

The following Option 3 items may be addressed in this White Paper, but are expected to be issues that will need further group discussion at various NERC committee levels.

- Redispatch would take place regardless of the transmission service priorities that are impacting the constraint.
- Several regulatory requirements may exist.
- Tool needs to be able to test against multiple TLRs.
- Responsibility for relief is transferred from the owners of the tagged transactions to the ultimate net sources and sinks.

Pros

- Significantly reduces the amount of transactions being curtailed
- Improves certainty of relief achieved.
- Reduced time needed to relieve a constraint
- More cost effective for the overall Eastern Interconnection
- More local action for relief minimizes potential impact on other Flowgate and could reduce potential interaction between TLRs.

- Redispatch costs provide market signal for potential system improvements.
- Redispatch adjustments can be applied on a reduce interval period (less than current 1 hour basis)
- Redispatch can be adjusted (up or down) throughout the hour leading to more precise regulation of flow that would further optimize redispatch costs incurred.
- May reduce staffing currently needed to implement transactional curtailments.
- Improved reliability
    - Improved response time to mitigate potential SOL/IROLs
    - Increased certainty of the relief achieved.
    - Option 3 will reduce the need to curtail schedules that create situations where TLR holds for certain held directions prevent CA import from all directions, possibly leading to increased EEA usage or a higher probability of load shedding.
- Improved equity
    - Redispatch would be available for all TLR priority levels including support of non-firm schedules
    - Redispatch costs would be comparably assigned to each BA, proceeding to apply to each TLR priority level until proceeding to the next highest level.
    - Tags and internal transfers are treated equally within each priority level.
    - Option 3 allows for the future ability to define new priority levels that may apply to comparable treatment of inadvertent flows and situations where net scheduled Interchange does not equal tagged interchange.
- Improved economic efficiencies
    - Redispatched MWs will have higher effective shift factor resulting in much less movement of power compared with curtailing schedules, and it would be equivalent or better than redispatch used to achieve CA NNL responsibility.
    - Utilized redispatch will uses the big picture of redispatch combinations that can cross-traditional CA/RC boundaries. The resulting redispatch should be economical on a large scale, and therefore, barring unusual circumstances would likely be more economical than actions to cover curtailed tags and individual CA redispatch.
    - The big picture allows for a larger number of possible redispatch combinations, decreasing the probability that load shedding would be used as a control option.
    - Current curtailment processes involve a large amount of 24/7 staffing by RCs/CAs/PSEs. Simplified redispatch procedures, may reduce some of these manpower expenses or free up those individuals to perform other functions. (Value would need to be determined via surveys)
- Provides checks and balances
    - Economic signal promoting full tagging of schedules
    - Economic signal for promoting improved tagging of dynamic schedules
    - Economic signal for improved energy imbalance compliance.

Cons

The following Option 3 items are considered to be potential drawbacks or items requiring significant effort to implement.

- It is a complete paradigm shift.
- Requires significant communications among RAs that above that currently achieved.
- It would require significant commitment by the NERC community to address the policy and legal filing issues related to implementation of a mandatory financial compensation process.
- Non-prescriptive relief requirements on RCs to order dispatch may result in a less-than-optimal solution to relief.
- Significant overhead in determining the financial impacts among affected parties per each congestion event.
- Sophisticated tools will need to be required and developed to identify redispatch combinations involving multiple units across multiple Flowgates.
- All BA's within an interconnection will need to agree to the settlement process and execute any necessary filings.

Data Requirements

- Real-time generation output of units.
- Real-time telemetry of all Flowgates and OTDF flows
- State estimated value (in lieu of telemetry)
- SDX-based generation values (temporary, until real-time data can be provided)

Use SDX unit status information to capture quick-start, min run times, temporary deratings, etc.

APPENDICES

CONCEPTS OF RELIEF RESPONSIBILITY

Options 2 and 3 presented in this white paper first require the calculation of relief responsibility for each BA. The concepts for calculating both internal and external relief responsibilities to be utilized in Options 2 and 3 are described in this appendix..

Internal Relief Responsibility (IRR)

The calculation of IRR is meant to capture the impacts on Flowgates of a Balancing Authority dispatching internal generation to meet its internal load requirements. These impacts will be calculated much like Network and Native Load (NNL) impacts are calculated by the IDC today, building on the Per Generator methodology (see part F of Operating Manual Appendix 9C1, *Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service*) and the Market Flow calculation method described in the MISO-PJM Congestion Management Whitepaper.

The IRR calculation differs from the Per Generator Method in the following ways:

- The contribution (GLDF) of all Balancing Authority generators will be used down to 0% with no threshold.
- Where specific generators are known to be supporting transactions into or out of the Balancing Authority, their contributions will be removed from the IRR calculation.
- The contribution of all Balancing Authority generators is based on the real-time and projected output level of each individual unit.
- The contribution of the Balancing Authority load is based on the real-time and projected demand for the total area.

Contributions from remote generators or loads that are electronically transferred into the Balancing Authority as pseudo ties will be included in the IRR calculations, consistent with the Dynamic Transfer White Paper.

If a Balancing Authority contains multiple Control Areas, non-tagged transactions between those internal control areas are reflected in the calculation of the internal relief responsibility.

Adjustments will be made for the IRR calculation to limit either the demand or generation if the Balancing Authority is a net importer or net exporter. The adjustments will be made if:

- The BA is an exporter, its generation will be reduced to meet its demand
- The BA is an importer, its demand will be decreased to equal its generation

The calculation of IRR may be performed on either a total net basis, or calculated individually for each TLR priority level. Following through with processes used for IDC Change Order 114 (CO-114), the IRR could incorporate priority 6-NN and 2-NH IRR attributable to Market Flow differences from "historical NNL" values. However, these new calculations would need to incorporate counter-flow effects and would not be directional as implemented for CO-114.

When separated out at the TLR "bucket" level, it is proposed that only the positive impacted IRR be used for financial compensation. Similar to the process described for ERR calculation, no "credit" would be given for negative IRR. Therefore, when separating IRR by TLR level, the sum of each level will not necessarily equal the net IRR calculation.

External Relief Responsibility (ERR)

The calculation of ERR is meant to capture the transactional impacts on Flowgates of a Balancing Authority's net interchange distributed across the interconnection. These impacts will be calculated using the shift factors associated with all of the importing and exporting Balancing Authorities throughout the Eastern Interconnection and adjacent interconnections. To the extent that transfer with adjacent interconnects contribute to congestion in the Eastern Interconnection, relief responsibility would be assigned to those interconnections.

The net interchange is determined by subtracting the total demand (and losses) from the net generation contained within the Balancing Authority's electronic boundaries.

If a Balancing Authority's net interchange is positive, it is classified as an exporting area, if negative, it is classified as an importing area. Each exporting (sending) Balancing Authority's weighted generation shift factors (GSF_{wba}) are calculated from each generator's GSF (weighted by generator output), and are used for calculating a weighted average GSF (GSF_w) for all exporting areas. Each importing (receiving) Balancing Authority's weighted load shift factors (LSF_{wba}) are calculated and are used for calculating a weighted average LSF (LSF_w) for all importing areas.

The ERR for a Balancing Authority is a function of its net interchange distributed to or from the other Balancing Authorities:

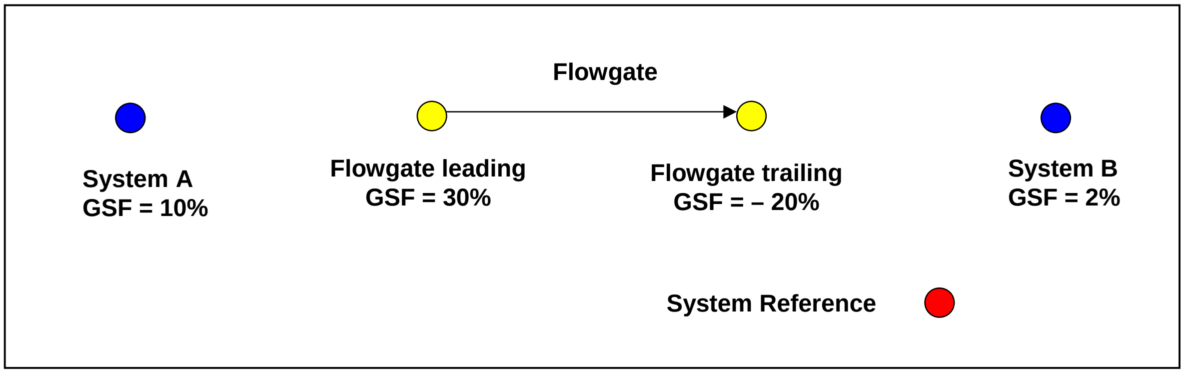
- For exporters: ERR = (GSF_{wba} minus LSF_w) * Net Interchange
- For importers: ERR = (GSF_w minus LSF_{wba}) * Net Interchange

The calculation of ERR may be performed on either a total net basis, or calculated individually for each TLR priority level. When separated out at the TLR "bucket" level, it is proposed that only the positive impacted ERR be used for financial compensation. Similar to the process for IRR, no "credit" would be given for negative ERR. Therefore, when separating ERR by TLR level, the sum of each level will not necessarily equal the net ERR calculation. Separating by TLR level also allows for situations where a BA can have non-firm ERR attributable to net non-firm export while at the same time having firm ERR attributable to net firm import.

Adjustments to over-stating ERR

Without adjustments to the weighted ERR calculations presented, the ERR will overstate responsibility by a factor of 2 because it is calculated for each BA. The December 2002 IDCGTF presentation to the NERC ORS did not address this potential over-counting of ERR. The IDCGTF has been aware of the problem, and as a basic solution the IDCGTF has discussed the need to divide the ERR by a factor of 2. However, there may be better approaches to dividing the relief responsibility. Therefore, the IDCGTF has proposed splitting the ERR based on a method that utilizes moving the shift factor reference location to be based on the Flowgate definition. This new reference would be different for each Flowgate. The reference would be a hypothetical location that incorporates an even participation of both the leading and trailing ends of the Flowgate monitored facilities. Rather than describe this as the Flowgate middle, it may be described as a hypothetical Flowgate "straddle" location. With the shift factors referenced to the "Flowgate Straddle" reference (FSR), the net Flowgate impact remains the same, but the assignment of ERR will be proportional to the shift factor size to reference. The use of a "Flowgate Straddle Reference" will allow ERR to be assigned relative to the electrical distance from a Flowgate. In doing so, remote BA's will receive a smaller component of ERR than would be assigned assuming a 50/50% ERR split.

The following simple example shows how the “Flowgate Straddle Reference” (FSR) would work. The drawing below shows the GSFs for systems through a specific Flowgate to the system reference (swing bus).



The net impact of an A to B 100 MW transfer would be 8 MW (100*(.10-.02)). Divide by 2, or split 50/50, each system would be assigned 4 MW of ERR.

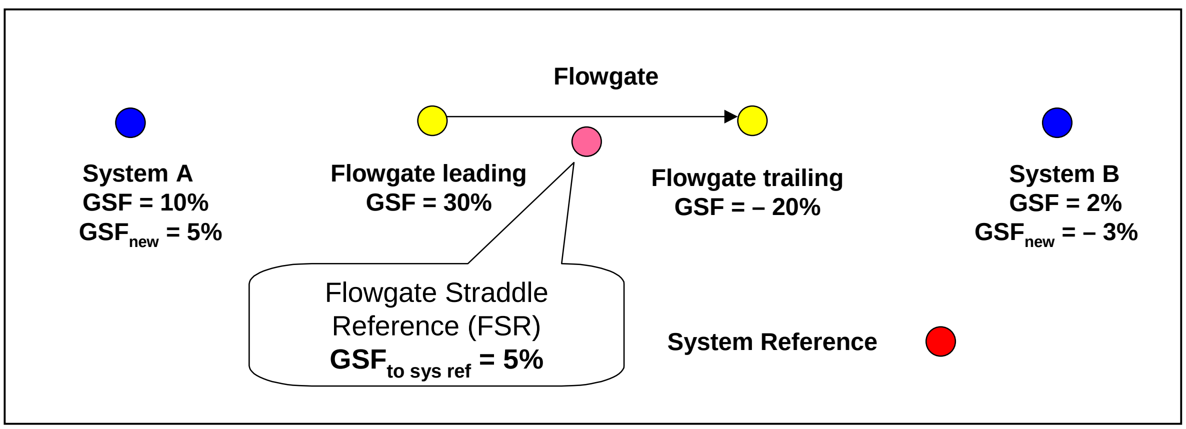
The Flowgate Straddle Reference GSF to the system reference would be 5% (middle of 30 and –20). Through linear properties, the GSF’s can be reassigned a references location by performing the following simple offset.

A ➔ New Reference = (A ➔ Old Reference) + (Old Reference ➔ New Reference)

= (A ➔ Old Reference) - (New Reference ➔ Old Reference)

or $GSF_{new\ ref} = GSF_{old\ ref} - GSF_{new\ ref}$

The figure below adjusts the GSFs to the new reference.



Using the new FSR, the 100 MW transfer continues to have an 8 MW impact (100*(.05-(-.03))). However the assignment of ERR can now be made such that 5 MW of ERR are assigned to System A, and 3 MW are assigned to system B (a 63/37% split). The assignment splits across the straddle reference using the equations below referenced to the new SFR. ERR split responsibility will be proportional to the GSF distance from the new FSR.

$$ERR_{export} = |GSF_{export}| / (|GSF_{export}| + |GSF_{import}|) * Impact$$

$$= |GSF_{export}| / (|GSF_{export}| + |GSF_{import}|) * (\text{Transfer MW}) * (GSF_{export} – GSF_{import})$$

similarly,

$$ERR_{import} = |GSF_{import}| / (|GSF_{export}| + |GSF_{import}|) * (\text{Transfer MW}) * (GSF_{export} – GSF_{import})$$

For multi-element Flowgates, a similar FSR can be determined giving equal weight to each monitored element of the Flowgate.

ASSESSMENT OF OPTIONS AGAINST 2002 IDCGTF CRITERIA

In 2002, the ORS charged the IDCGTF with developing options for improving the granularity of the IDC. Six initial criteria were agreed to. Subsequently, the Market Interface Practices Subcommittee (MIPS) of the NERC Market Interface Committee requested an additional seven criteria be used by the IDCGTF in their development of granularity options.

1. Must have accurate flow-based information reflective of true operating behavior — Use of real-time or near real-time data makes the IDC far more reflective of actual operating conditions.

2. Should accommodate movement toward SMD — The recommended method accommodates multiple market approaches

3. Output must give Reliability Coordinators necessary information to assign congestion relief that meets comparable treatment standards — The alternatives for output from the impact calculator to the Reliability Coordinators, Reliability Authorities, and Balancing Authorities will provide unbiased curtailment recommendations and options. Markets will have the ability to use their market-based methods, which are approved by FERC as being equitable, and others will have to define and gain approval of their congestion management methods.

4. Must give Reliability Coordinators accurate information to assign relief responsibilities that will produce effective electrical results — The recommended method using a zonal approach for transactions and feasible paring of effective generators will be able to provide more effective electrical results than the current IDC method.

5. Design should seek to eliminate known or possible abusive behavior — The recommended method eliminates the capability of disguising transactions using multiple tags (size) between multiple parties. Use of net interchange to calculate responsibility provides no TLR advantages for hubbing activities. Such practices will not change the calculation of the responsibilities, since determination of external relief responsibilities will be based on net sources and sinks.

6. Design should allow for market mechanisms to meet relief responsibilities — The recommended method allows for market-based relief mechanisms.

Additional criteria (Suggested by MIPS)

7. Changes should be cost effective and justified by a business case — a business case will be developed once philosophical approval is achieved.

8. Changes should require minimal effort, given industry migration to SMD — This is no longer an issue

9. Any funding should be evaluated based upon primary users — needs to be addressed in SPIP, decided by the Cost Allocation Subcommittee and the Board of Trustees.

10. Include an estimate of the longevity of the changes — The recommendation should accommodate reliability and foreseeable market changes over the next 5-10 years. The existing IDC system has already been in place for 5 years, and will have been in place for two or more additional years by the time the recommendation could be placed in service.

11. Should resolve issues related to unique operating conditions — By application of real-time data in the model, peer review of zonal definitions, and peer review of unique applications

such as pseudo ties and dynamic schedules, all unique operating conditions should be addressed.

12. Should minimize use of subjective evaluations related to creating the model — Creation of zonal boundaries would have to meet a criteria, which is yet to be defined.

13. Should recognize that some groups use the existing systems as settlement tools and that changes may affect the ability of those groups to continue that use — Entities that use the existing system as part of settlement tools have the onus to ensure that they can cope with the new system. The existing system was never designed for those purposes. Tracking of actions taken to achieve relief should be documented in the TLR logs.

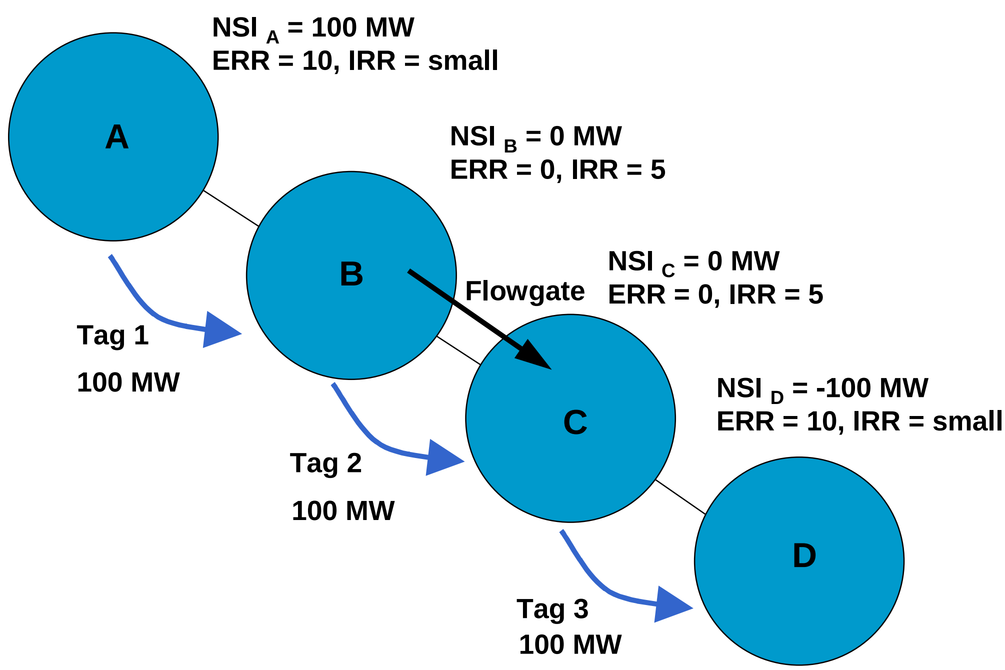
The following table describes how the three options discussed in this paper conform to the granularity criteria.

Criteria	Option 1	Option 2	Option 3
1. Must have accurate flow-based information reflective of true operating behavior	Initially would not meet, but could be adapted by supplying marginal generation for all areas	Meets criteria — Requires near-real-time data	Meets criteria — Requires near-real-time data
2. Should accommodate movement toward SMD	Accommodates multiple market approaches (due to CO-114)	Accommodates multiple market approaches	Accommodates multiple market approaches
3. Output must give RC's necessary information to assign congestion relief that meets comparable treatment standards	TLR process is prescriptive on a comparable basis	Comparable curtailment options provided but use not ensured	Priorities may not be used in Relief Responsibility calculations – comparable treatment would be handled in settlement process
4. Must give RC's accurate information to assign relief responsibilities that will produce effective electrical results	Improves accuracy over current method	Improves accuracy over current method – use of near-real-time data improves accuracy of participation	Most electrically effective and economic solution provided
5. Design should seek to eliminate known or possible abusive behavior	Does not eliminate all abuses — peer review of zonal methods adds check against some abuse	IRR/ERR calculation eliminates abuses for non-tagging and hubbing	IRR/ERR calculation eliminates abuses for non-tagging and hubbing
6. Design should allow for market mechanisms to meet relief responsibilities	Meets criteria with respect to CO 114	Meets criteria	Meets criteria in settlement
7. Changes should be cost effective and justified by a business case	NERC Standards and Project Implementation Plans require this	NERC Standards and Project Implementation Plans require this	NERC Standards and Project Implementation Plans require this
8. Changes should require minimal effort, given industry migration to SMD	Not applicable criteria any longer	Not applicable criteria any longer	Criteria no longer applicable

Criteria	Option 1	Option 2	Option 3
9. Any funding should be evaluated based upon primary users	CAS will determine	CAS will determine	CAS will determine
10. Include an estimate of the longevity of the changes	Good until Option 2 is implemented	Good until someone figures out it takes too long to get relief	For foreseeable future
11. Should resolve issues related to unique operating conditions	Relieves unique dispatch and zonal issues	Relieves unique dispatch and zonal issues, and IRR/ERR covers difference in impact for importing and exporting	Relieves unique dispatch and zonal issues, and IRR/ERR covers difference in impact for importing and exporting
12. Should minimize use of subjective evaluations related to creating the model	Peer review of zonal methods eliminates subjectivity	Peer review of zonal methods eliminates subjectivity	Peer review of zonal methods eliminates subjectivity
13. Should recognize that some groups use the existing systems as settlement tools and that changes may affect the ability of groups to continue that use	Most, if not all, settlement tools use the tags, not the IDC. Unless tags are eliminated, this is not an issue.	Most, if not all, settlement tools use the tags, not the IDC. Unless tags are eliminated, this is not an issue.	Most, if not all, settlement tools use the tags, not the IDC. Unless tags are eliminated, this is not an issue.

EXAMPLE 1: UNEXPECTED RELIEF DURING CURTAILMENT DUE TO TRANSACTION LINKAGES

The flowing example illustrates how Option 3 may accomplish relief in a manner different from that using transactional curtailment of relief. The example shows a Flowgate between systems B and C that is called for TLR. All tags and NNL impacts are considered to be at the same priority level (firm). Using IRR and ERR calculations, characteristic IRR and ERR values are listed. Systems A and D have an ERR due to their net transactions. Systems B and C do not have an ERR because of their zero net interchange. Systems And D have a very small or zero IRR due to their distance from the Flowgate. Systems B and C are assumed to have an IRR due to proximity of their generation to load transfers to the Flowgate. Tag 2 is considered to have a high TDF (>5%) for the Flowgate, whereas, Tags 1 and 3 are considered to have small TDFs for the Flowgate (<5%).



In order to achieve the transactional relief as prescribed in the existing IDC (also for Option 1 and to some extent for Option 2), the Tag 2 can be curtailed to reduce the Flowgate flow. In the process of curtailing, systems B and C may be burdened. It is undetermined if the transaction for Tag 1 (A to B) and Tag 3 (C to D) are linked to the curtailment of Tag 2 (B to C). If they are linked, it is possible that the prescribed curtailment of Tag 2 will result in the un-prescribed curtailment of these additional tags. These un-prescribed actions during a TLR event may have undesirable affects that make it additionally more difficult for Reliability Coordinators to regulate flow on the Flowgate.

Alternately, Option 3 would achieve the more precise desired relief in a manner that assigns relief to the ultimate parties that are considered to contribute to the flow. Under Option 3, the Reliability coordinator will find a redispatch combination to provide Flowgate relief. In this linear example there are many combinations that may be effective in terms of shift factor and economics. However, in a less simple example, it would be more likely the redispatch combination would be in proximity of the Flowgate. Therefore, lets assume that the redispatch will reduce generation of a unit in system B, and increase generation for a unit in system C. Costs will be assigned to systems A and D for their ERRs, and cost will be assigned to systems B and C for their IRRs. In doing so, the ERR component of relief is passed to systems A and D, as compared to systems B and C for transactional based curtailments. If systems A and D are unhappy with these cost assignments, they may voluntarily curtail transactions to reduce their ERR, thus reducing their cost for the next relief period. In this way, the cost assignments send the proper pricing signal. The example given is for a linearly linked group of systems with a limited number of transactions. Keep in mind the use of the Flowgate Straddle Reference (FSR) in a real example, will reduce the ERR for systems that are remote from a Flowgate in TLR.

EXAMPLE 2: COMPARISON EXAMPLE OF OPTION 3 VERSUS THE CURRENT IDC METHODOLOGY

The following section contains an example comparing Option 3 against current IDC practices for Flowgate 3719 [Salem 345/161 (for loss of) Quad Cities-Sub 91] located within the ALTW control area. The data for the example is based on data taken from screen snapshots within the IDC.

The following table shows how redispatch cost would be allocated using the ERR and IRR methodologies in Option 3. The example uses Control Areas as the responsible Balancing Authorities. The following example is based on data obtained from snapshots of the IDC. At the time the data was extracted the Flowgate was not in TLR. The example arbitrarily assumes that 40 MW of relief is needed on Flowgate 3719. The example also makes an assumption that 100 MW can be redispatched between a pair of generators with an effective net shift factor of 40% (100 x 40% = 40 MW or relief). The redispatch pair in this example is arbitrary and fictitious, although quite realistically, assumed to have a unit price differential of $20. (For example, the best redispatch pair for Flowgate 3719 is Quad or Cordova against Dubuque with an effective shift factor of 34%.)

Area	Name	GSF equiv	Exp or Imp	GSF wtavg with FSR	LSF	LSF wtavg with FSR	**IRR**	Positive IRR	**ERR**	Positive ERR	Pos ERR+ IRR	IRR Charge	ERR Charge	Host Charge	Total Charge	Pct of Total	
363	CE	3.2%	3682	0.97%	1.1%	0.3%	28	28.0	68.0	68.0	**96.0**	$112	$273		$385	19.3%	CE
331	ALTW	-8.3%	-601	0.97%	-6.3%	0.3%	27.2	27.2	16.5	16.5	**43.7**	$109	$66	$500	$676	33.8%	ALTW
364	ALTE	0.0%	-693	0.97%	-2.8%	0.3%	27.9	27.9	6.9	6.9	**34.8**	$112	$28		$140	7.0%	ALTE
600	NSP	-7.0%	-696	0.97%	-5.5%	0.3%	12.8	12.8	16.4	16.4	**29.2**	$51	$66		$117	5.9%	NSP
635	MEC	-5.8%	-144	0.97%	-3.2%	0.3%	22.7	22.7	1.7	1.7	**24.4**	$91	$7		$98	4.9%	MEC
142	DUK	0.7%	2154	0.97%	0.0%	0.3%	0	0.0	12.9	12.9	**12.9**	$0	$52		$52	2.6%	DUK
206	OVEC	1.2%	1519	0.97%	0.0%	0.3%	0	0.0	12.7	12.7	**12.7**	$0	$51		$51	2.5%	OVEC
626	OTP	-6.5%	-308	0.97%	-4.7%	0.3%	1.9	1.9	6.0	6.0	**7.9**	$8	$24		$32	1.6%	OTP
357	IP	0.2%	871	0.97%	0.3%	0.3%	4.3	4.3	3.4	3.4	**7.7**	$17	$14		$31	1.5%	IP
205	AEP	1.2%	562	0.97%	0.5%	0.3%	2.4	2.4	4.7	4.7	**7.1**	$10	$19		$28	1.4%	AEP
215	DLCO	1.2%	835	0.97%	0.0%	0.3%	0	0.0	7.0	7.0	**7.0**	$0	$28		$28	1.4%	DLCO
140	CPLE	0.8%	833	0.97%	0.0%	0.3%	0	0.0	5.4	5.4	**5.4**	$0	$22		$22	1.1%	CPLE
412	SEC	0.3%	1100	0.97%	0.0%	0.3%	0	0.0	4.7	4.7	**4.7**	$0	$19		$19	0.9%	SEC
650	LES	-5.4%	-384	0.97%	-3.2%	0.3%	-5.8	0.0	4.6	4.6	**4.6**	$0	$19		$19	0.9%	LES
147	TVA	0.1%	1305	0.97%	0.1%	0.3%	-6.4	0.0	4.4	4.4	**4.4**	$0	$18		$18	0.9%	TVA
25	PJM	1.1%	-4214	0.97%	0.0%	0.3%	0	0.0	3.9	3.9	**3.9**	$0	$16		$16	0.8%	PJM
366	WPS	-0.5%	-62	0.97%	-1.5%	0.3%	3.7	3.7	0.2	0.2	**3.9**	$15	$1		$16	0.8%	WPS
211	LGEE	1.0%	396	0.97%	0.4%	0.3%	0.8	0.8	2.9	2.9	**3.7**	$3	$12		$15	0.7%	LGEE
207	HE	0.9%	492	0.97%	0.0%	0.3%	0	0.0	3.6	3.6	**3.6**	$0	$14		$14	0.7%	HE
130	AECI	-1.5%	-822	0.97%	-0.9%	0.3%	1.9	1.9	1.2	1.2	**3.1**	$8	$5		$12	0.6%	AECI
705	NBPC	1.2%	362	0.97%	0.0%	0.3%	0	0.0	3.0	3.0	**3.0**	$0	$12		$12	0.6%	NBPC
640	NPPD	-5.5%	190	0.97%	-3.4%	0.3%	2.7	2.7	-4.2	0.0	**2.7**	$11	$0		$11	0.5%	NPPD
367	MGE	0.0%	-151	0.97%	-1.8%	0.3%	1.6	1.6	0.8	0.8	**2.4**	$6	$3		$9	0.5%	MGE
145	VAP	1.0%	313	0.97%	0.0%	0.3%	0	0.0	2.4	2.4	**2.4**	$0	$9		$9	0.5%	VAP
208	CIN	1.1%	285	0.97%	0.5%	0.3%	-0.1	0.0	2.3	2.3	**2.3**	$0	$9		$9	0.5%	CIN
151	EES	-0.5%	-22	0.97%	-0.3%	0.3%	2.1	2.1	0.0	0.0	**2.1**	$8	$0		$9	0.4%	EES
362	EEI	-0.2%	1115	0.97%	0.0%	0.3%	0	0.0	2.1	2.1	**2.1**	$0	$9		$9	0.4%	EEI
541	KCPL	-3.2%	154	0.97%	-1.7%	0.3%	2.1	2.1	-1.6	0.0	**2.1**	$8	$0		$8	0.4%	KCPL
365	WEC	1.5%	-919	0.97%	-0.3%	0.3%	0.4	0.4	1.4	1.4	**1.8**	$2	$6		$7	0.4%	WEC
146	SOCO	0.1%	477	0.97%	0.1%	0.3%	-8.1	0.0	1.7	1.7	**1.7**	$0	$7		$7	0.3%	SOCO
202	FE	1.2%	-1762	0.97%	0.0%	0.3%	0	0.0	1.6	1.6	**1.6**	$0	$7		$7	0.3%	FE
540	MPS	-3.2%	-209	0.97%	-1.7%	0.3%	0.3	0.3	0.9	0.9	**1.2**	$1	$4		$5	0.2%	MPS
536	WR	-2.9%	-349	0.97%	-1.5%	0.3%	-1.5	0.0	1.2	1.2	**1.2**	$0	$5		$5	0.2%	WR
401	FPL	0.3%	-1267	0.97%	0.0%	0.3%	0	0.0	1.2	1.2	**1.2**	$0	$5		$5	0.2%	FPL
416	TEC	0.3%	272	0.97%	0.0%	0.3%	0	0.0	1.2	1.2	**1.2**	$0	$5		$5	0.2%	TEC
703	IMO	1.3%	-1138	0.97%	0.0%	0.3%	0	0.0	1.1	1.1	**1.1**	$0	$4		$4	0.2%	IMO
702	NYIS	1.2%	-1134	0.97%	0.0%	0.3%	0	0.0	1.1	1.1	**1.1**	$0	$4		$4	0.2%	NYIS
774	HQOH	1.3%	110.2	0.97%	0.0%	0.3%	0	0.0	1.0	1.0	**1.0**	$0	$4		$4	0.2%	HQOH
						Other lower impacted systems not shown					"	"	"		"	"	
Total			0.00				78.8	**145**	151.2	**229.1**	**373.6**	**$580**	**$920**	$500	**$2,000**	100%	

No start-up costs or fixed costs are considered for this example. Therefore, the redispatch has an hourly cost of $2,000 ($20 x 100). In order to emphasize the local responsibility for the Flowgate, the “host” Control Area (ALTW) with the Flowgate is assumed to have a direct assignment of a limited portion of the redispatch costs, with the remainder socialized using the ERR and IRR formulation.

In the Option 3 example, 25% of the redispatch costs ($500) are assigned directly to the ALTW control area. The remaining 75% ($1,500) is distributed among the control areas. The Flowgate Straddle Reference was applied based on an estimate of its value. As a result, application of Option 3, allocates 33.8% of the cost to ALTW, and 70.8% of the total cost to the top 5 CAs of ALTW, CE, ALTE, NSP, MEC, and 83.0% to the top 11 CAs comprising at least 1% of the total cost.

A comparison of the same example using current IDC assumptions is listed below. The data shows that there are no non-firm tags to curtail above 5% TDF. (There are some non-firm tags between 3-5% TDF.) Therefore a comparable example would require the IDC to use curtailed firm tags and CA NNL responsibility to achieve 40 MW of relief. The example requires 20.3 MW of CA NNL relief from ALTW and CE.

Based of GSFs in the IDC snapshots, the most effective CE redispatch combination would be reducing Quad Cites (nuclear) against Kincaid for an effective shift factor of 6%, and for ALTW the best combination would be reducing Burlington against Dubuque for a shift factor of 26 %. This type of GSF data is readily available thought the NERC TDF viewer, and does not necessarily represent units that would be chosen to move. However, the information may show that a single CA may not have within it available means the ability to provide an effective redispatch pair. For this reason, even using today’s IDC, CAs may find it in their benefit to coordinate redispatch across their boundaries.

The corresponding approximate IDC actions would curtail 9 tags a total of 290 MW (19.7 divided by 6.8% effective TDF) to achieve the 19.7 MW of tag relief.

	Impact MWs >=5%	Tag MWs >=5%		Impact MWs 3-5%	Tag MWs 3-5%	
NF Total	0	0		9.4	275	(6 tags)
7-F Total	36	529	(9 tags)	50.7	1335	(21 Addl tags)
TOTAL	36	529		60.1	1610	
Effective TDF =		6.8%			3.7%	

Above 5%	**Energy on FG**	**Name**
NNL	**23.4**	**Total for CE**
NNL	**13.6**	**Total for ALTW**
Total	**37.0**	

Firm Relief Needed: 40

Total	Relief	
37.0	**20.3**	Firm NNL
36.0	**19.7**	Tags
	40.0	

Item 9. Policy 3 as Version 0

Background

Policy 3 Standard Version 0 will merge the terms of the NERC Reliability Functional Model into the document. A concise timeframe for completing this work has been identified. The subcommittee should complete as much of the conversion of Policy 3 as possible during this meeting. This conversion will include:

- Ensuring that all Policy 3 business practices have been addressed by NAESB.
- Re-writing Policy 3 using Function Model functions.
- Tracking the conversion to demonstrate to the industry that no new requirements have been added or deleted from Policy 3.

Al Boesch will lead the discussion as the group begins the process of converting Policy 3 to Version 0.

Attachment

9a Policy 3 — Standards Reference Table

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Section A			
1. INTERCHANGE TRANSACTION arrangements. The PURCHASING-SELLING ENTITY shall arrange for all Transmission Services, tagging, and contact personnel for each INTERCHANGE TRANSACTION to which it is a party	None	**CI Standard** under Req 1.0, 1.1, 2.0,9.0	Deal arrangements are not part of the new Standard
1.1 The PURCHASING-SELLING ENTITY shall arrange the Transmission Services necessary for the receipt, transfer, and delivery of the TRANSACTION.	None	**CI Standard** under Req 1.1	Deal arrangements are not part of the new Standard
1.2 Transmission services. **Tagging.** The PURCHASING-SELLING ENTITY serving the load shall be responsible for providing the INTERCHANGE TRANSACTION tag. (Note: 1. Any PSE may provide the tag; however, the load-serving PSE is responsible for ensuring that a single tag is provided. 2. If a PSE is not involved in the TRANSACTION, such as delivery from a jointly owned generator, then the SINK CONTROL AREA is responsible for providing the tag. PSEs must provide tags for all INTERCHANGE TRANSACTIONS in accordance with Requirement 2.)	None	**CI Standard** refers to "tag" as it is called today as the "RAI", Request for Arranged Interchange.	This requirement is dependent on the future of the IDC Providing the tag is equivalent to providing the information to IDC.
1.3Contact personnel. Each PURCHASING-SELLING ENTITY with title to an INTERCHANGE TRANSACTION must have, or arrange to have, personnel directly and immediately	None	**1.2 is covered in the NAESB CI Standard under Req 9.0**	In the new standard the PSE is notified by the IA of the approval of the requested interchange but is not required to take any action.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
available for notification of INTERCHANGE TRANSACTION changes. These personnel shall be available from the time that title to the INTERCHANGE TRANSACTION is acquired until the INTERCHANGE TRANSACTION has been completed.			
1.4 E-Tag monitoring. CONTROL AREAS, TRANSMISSION PROVIDERS, and PURCHASING-SELLING ENTITIES who are responsible for a tagged TRANSACTION shall have facilities to receive unsolicited notification from the Tag Authority of changes in the status of a tag with which the user is a participant.	The parallel to this requirement would be the requirement to have facilities to receive interchange information from the IA(s). This requirement is implied in Coordinate Interchange Standard (measure 403) for the TSP and BA.	**1.4 is covered for the PSE in the NAESB CI Std. The TSP and CA/BA are required to respond (but does not require the people or facilities to continuously monitor) to requests by the IA in the NERC CI Std.**	The tag authority is not in the functional model
2.1 Application to TRANSACTIONS. All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged. 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	**Standard Reference-** Coordinate Interchange Standard (measure 401) The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.	None	There is no requirement for tagging in the standard. The big question is will IDC still be in existence? If so will the IA provide the IDC with the appropriate information?

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

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.) • 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). **[See also, Policy 1E2 and 2.1, "Disturbance Control Standard"]**			
2.2 Parties to whom the complete tag is provided. The tag, including all updates and notifications, shall be provided to the following entities: • Generation Providing Entity • Generation CONTROL AREA • TRANSMISSION PROVIDERS • Transmission Customers • Scheduling Entities (INTERMEDIARY CONTROL	**Standard Reference-** There is no requirement for a tag. However the Coordinate Interchange Standard (measure 404) requires: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange.	**1.7 is covered under the NAESB CI Std:** Requires the IA to provide everyone involved in transaction a copy of the RAI (Tag in a CA paradigm).	

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
AREAS) • Intermediate PURCHASING-SELLING ENTITIES (Title-Holders) • Load CONTROL AREA • LOAD-SERVING ENTITY • Market Redispatch Notification Entities (if specified) • Security Analysis Services			
2.3 **Method of transmitting the tag.** The PURCHASING-SELLING ENTITY shall submit the INTERCHANGE TRANSACTION tag in the format established by each INTERCONNECTION **2.3.1Tags for INTERCHANGE TRANSACTIONS that cross INTERCONNECTION boundaries.** Procedures are found in **Appendix 3A2, "Tagging Across Interconnection Boundaries."**	None	**1.7.1 is covered under the NAESB CI Std** (in the RAI Data table) under Req 3.0 for the type of data required and requests the data to be electronically. Does not specify a particular format.	Format will not be part of a Reliability Standard. Note Appendix 3A2 needs to be updated to reflect the use of tags in the Western Interconnection
2.4 INTERCHANGE TRANSACTION submission time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTIONS shall be submitted as specified in **Appendix 3A1, "Tag Submission and Response Timetable."**	None	**This is covered in the NAESB CI Std** and is called the RAI submission and Response timetable for the Market period and the Arranged Interchange Response timetable for the Reliability period.	There will not be any timing requirements in the reliability standard. If the tag is not submitted in time the deal does not happen.
2.4.1Exception for security reasons. Exception to the submission	None	**Not covered in the NAESB Standards.** May want to consider in	Changes for reliability reasons is addressed in the measures for requirement

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
time requirements in Section 0 is allowed if immediate changes to the INTERCHANGE TRANSACTIONS are required to mitigate an OPERATING SECURITY LIMIT violation. The tag may be submitted after the emergency TRANSACTION has been implemented but no later than 60 minutes.		a NERC Std.	402 of the Coordinate Interchange Standard, however there are not any timing requirements.
2.5 Confirmation of tag receipt. Confirmation of tag receipt shall be provided to the PURCHASING-SELLING ENTITY who submitted the tag in accordance with INTERCONNECTION tagging practices. **["E-Tag Reference Document"]**	None		Not in the coordinate interchange standard. If the interchange is confirmed the PSE will be notified by the IA.
2.6 Tag acceptance. An INTERCHANGE TRANSACTION tag shall be accepted if all required information is valid and provided in accordance with the tagging specifications in Requirement 2.	Coordinate Interchange Standard Requirement 403. The Reliability Authority, Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities	**Covered in the NAESB CI Std** under Requirement 4.0	The Standard does not require acceptance but the criteria for review is defined to be reliability related.
3. INTERCHANGE TRANSACTION tag receipt verification. The SINK CONTROL AREA shall verify the receipt of each INTERCHANGE TRANSACTION	Coordinate Interchange Standard Requirement 402. The IA confirms the interchange with the BAs and TSPs.		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
tag with the TRANSMISSION PROVIDERS, and CONTROL AREAS on the SCHEDULING PATH before the INTERCHANGE TRANSACTION is implemented.			
4. INTERCHANGE TRANSACTION assessment. Generation Providing Entities, LOAD SERVING ENTITIES, TRANSMISSION PROVIDERS, CONTROL AREAS on the SCHEDULING PATH, and other operating entities responsible for operational security shall be responsible for assessing and "approving" or "denying" INTERCHANGE TRANSACTIONS as requested by PURCHASING-SELLING ENTITIES, based on established reliability criteria and adequacy of INTERCONNECTED OPERATIONS SERVICES and transmission rights as well as the reasonableness of the INTERCHANGE TRANSACTION tag. GENERATION PROVIDING ENTITIES and LOAD SERVING ENTITIES may elect to defer their approval responsibility to their HOST CONTROL AREA. This assessment shall include the following: **The CONTROL AREA assesses:** • TRANSACTION start and end time • Energy profile (ability of generation maneuverability to accommodate) • SCHEDULING PATH (proper connectivity of ADJACENT CONTROL AREAS)	Coordinate Interchange Standard Requirement 403: The Reliability Authority, Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.	**The NAESB CI Std Req** 4.0 and 5.0 addresses this.	Loss Accounting is not addressed.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
The TRANSMISSION PROVIDER assesses: • Valid OASIS reservation number or transmission contract identifier • Proper transmission priority • Energy profile accommodation (does energy profile fit OASIS reservation?) • OASIS reservation accommodation of all INTERCHANGE TRANSACTIONS • Loss accounting **The Generation Providing Entity and LOAD-SERVING ENTITY assess:** • TRANSACTION is valid representation of contractually agreed upon energy delivery			
4.1 Tag corrections. During the CONTROL AREAS' and TRANSMISSION PROVIDERS' Assessment Time, the PURCHASING-SELLING ENTITY who submitted the tag may elect to submit a tag correction. Tag corrections are changes to an existing tag that do not affect the reliability impacts of the INTERCHANGE TRANSACTION; therefore, tag corrections do not require the complete re-assessment of the tag by all CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH, or the completion and submission of a new tag by the	None	**The NAESB CI Std Req** 6.0, 8.0, 8.1, 8.1.2, 8.2 and 5.0 addresses this for Market changes.	PSE adjust is a market function. Any market changes of approved interchange will follow the same process as an initial interchange request.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
PURCHASING-SELLING ENTITY. The SINK CONTROL AREA shall notify all CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH of the correction, and specifically alert those entities for which a correction has impact. Entities who are impacted by the correction will have an opportunity to reevaluate the tag status. The timing requirements for corrections are found in **Appendix 3A1, "Tag Submission and Response Timetable**." Tag items that may be corrected are found in **Appendix 3A4, "Required Tag Data."** A description of those entities who may correct an INTERCHANGE TRANSACTION tag is found in **Appendix 3D, "Transaction Tag Actions." [See Appendix 3A1 Subsection C, Interchange Transaction Corrections]**			
5. INTERCHANGE TRANSACTION approval or denial. Each CONTROL AREA or TRANSMISSION PROVIDER on the SCHEDULING PATH responsible for assessing and "approving" or "denying" the INTERCHANGE TRANSACTION shall notify the SINK CONTROL AREA. The SINK CONTROL AREA in turn notifies the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag, plus all other CONTROL AREAS and TRANSMISSION	Included in the Coordinate Interchange Standard Requirement 402 and 404. This process is the responsibility of the IA. The IA gathers approvals from the BA, RA and TSP. The IA communicates approval or denial to all entities involved.	**The Naesb CI Std** addresses this in Req. 4.0 and 5.0. Timing Requirements are addressed in Req. 4.1 for PSE timing and timing during the Reliability period are covered under 5.0	

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
PROVIDERS on the SCHEDULING PATH. Assessment timing requirements are found in **Appendix 3A1, "Tag Submission and Response Timetable."** A description of those entities who may approve or deny an INTERCHANGE TRANSACTION is found in **Appendix 3D, "Transaction Tag Actions."**			
5.1 INTERCHANGE TRANSACTION denial. If denied, this notification shall include the reason for the denial.	None	**Covered under NAESB CI** Std under Req. 5.1	
5.2 INTERCHANGE TRANSACTION approval. The INTERCHANGE TRANSACTION is considered approved if the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag has received confirmation of tag receipt and has not been notified that the transaction is denied.	Included in the Coordinate Interchange Standard Requirement 404: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange.	**Also covered in the NAESB Std** under Req. 5.0	
6. Responsibility for INTERCHANGE TRANSACTION implementation. The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL	Coordinate Interchange Standard Requirement 401: The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
AREAS on the SCHEDULING PATH in accordance with Policy 3B. **6.1 Tag requirements for INTERCHANGE TRANSACTION implementation.** The CONTROL AREA shall implement only those INTERCHANGE TRANSACTIONS that: • Have been tagged in accordance with Requirement 2 above, or, • Are exempt from tagging in accordance with Requirement 1.13 above.			
7. Tag requirements after curtailment has ended. After the curtailment of a TRANSACTION has ended, the INTERCHANGE TRANSACTION'S energy profile will return to the originally requested level unless otherwise specified by the PURCHASING-SELLING ENTITY. [See **Interchange Transaction Reallocation During TLR Levels 3a and 5a Reference Document, Version 1 Draft 6**]	None	**Not covered in the NAESB Standards.** May want to consider in a NERC Std.	Section 402 addresses reliability related changes but does not address actions when the reliability change is no longer necessary. This should be addressed somewhere.
8.Confidentiality of information. RELIABILITY COORDINATORS, CONTROL AREAS, TRANSMISSION PROVIDERS, PURCHASING-SELLING ENTITIES, and entities serving as tag agents or service providers as provided in the "**E-Tag Reference Document"** shall not disclose	None	Currently not covered in the **NAESB CI Std** Could it be covered in the Certification SARs.	This is a FERC issue.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
INTERCHANGE TRANSACTION information to any PURCHASING-SELLING ENTITY except as provided for in Requirement 2.2 above, **"Parties to whom the complete tag is provided."**			
Section B			
1. CONTROL AREAS must be adjacent. INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS.	None	**Not covered in the NAESB CI Std.**	This is not required in the functional model
2. Sharing INTERCHANGE SCHEDULES details. The SENDING CONTROL AREA and RECEIVING CONTROL AREA must provide the details of their INTERCHANGE SCHEDULES via the Interregional Security Network as specified in Policy 4.B.	Coordinate Interchange Standard Requirement 402. This is confirmed by the RA in the approval of interchange Coordinate Interchange Standard Requirement 404: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange.	**Not covered in the NAESB CI Std.**	The RA will receive the Interchange information.
3. Providing tags for approved TRANSACTIONS to the RELIABILITY COORDINATOR. The SINK CONTROL AREA	Coordinate Interchange Standard Requirement 404: The Interchange Authority shall	**Also covered in the Naesb Std under Req. 5.0**	

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
shall provide its RELIABILITY COORDINATOR the information from the INTERCHANGE TRANSACTION tag electronically for each Approved INTERCHANGE TRANSACTION.	communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange. Coordinate Interchange Standard Requirement 402. IA confirms that the RA has approved the interchange.		
4. INTERCHANGE SCHEDULE confirmation and implementation. The RECEIVING CONTROL AREA is responsible for initiating the confirmation and implementation of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA. **4.1 INTERCHANGE SCHEDULE agreement**. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the: • INTERCHANGE SCHEDULE start and end time • Ramp start time and rate • Energy profile This agreement shall be made before either the SENDING CONTROL AREA or RECEIVING CONTROL	Included in Coordinate Interchange Standard Requirement 402 measures.		The IA coordinates implementation of the interchange.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
AREA makes any generation changes to implement the INTERCHANGE SCHEDULE.			
4.1.2 Operating reliability criteria. CONTROL AREAS shall operate such that INTERCHANGE SCHEDULES or schedule changes do not knowingly cause any other systems to violate established operating reliability criteria.	**Standard Reference-** Coordinate Interchange Standard Requirement 403: The Reliability Authority shall acknowledge that the interchange is acceptable and reliable with respect to its functional responsibilities.		
4.1.3 DC tie operator. SENDING CONTROL AREAS and RECEIVING CONTROL AREAS shall coordinate with any DC tie operators on the SCHEDULING PATH.	None		Coordinate Interchange Standard Requirement 402 requires a transmission reservation but does not require coordination with the DC tie operator
5. Maximum scheduled interchange. The maximum NET INTERCHANGE SCHEDULE between two CONTROL AREAS shall not exceed the lesser of the following: **5.1 Total capacity of facilities.** The total capacity of both the owned and arranged-for transmission facilities in service between the two CONTROL AREAS, or **5.2 Total Transfer Capability.** The established network Total Transfer Capability (TTC) between the CONTROL AREAS, which considers other transmission	**Standard Reference-** Coordinate Interchange Standard Requirement 403: The Transmission Service Provider shall acknowledge that the interchange is acceptable and reliable with respect to its functional responsibilities.		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
facilities available to them under specific arrangements, and the overall physical constraints of the transmission network. Total Transfer Capability is defined in *Available Transfer Capability Definitions and Determination*, NERC, June 1996.			
Section D			
1. INTERCHANGE TRANSACTION modification for market-related issues. The PURCHASING-SELLING ENTITY that submitted an INTERCHANGE TRANSACTION tag may modify an INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started**.** These modifications may be made due to changes in contracts, economic decisions, or other market-based influences. In cases where a Market Operator is serving as the source or sink for a TRANSACTION, then they shall have the right to effect changes to the energy flow as well (based on the results of the market clearing). **1.1 Increases.** The INTERCHANGE TRANSACTION tag's energy and/or committed transmission reservation(s) profile may be increased to reflect a desire to flow more energy or commit more transmission than originally requested. Necessary transmission must be either available from the earlier TRANSACTION or provided with the increase.	None	**Covered under the NAESB CI Std** under Req. 6.0, 8.0, 8.1, 8.1.2, 8.2	For the purpose of the Coordinate Interchange Standard any changes for market related purposes follow the same process as the initial request For interchange

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
1.2 Extensions. The INTERCHANGE TRANSACTION tag's energy profile may be extended to reflect a desire to flow energy during hours not previously specified. Necessary transmission capacity must be provided with the extension. **1.3 Reductions.** The INTERCHANGE TRANSACTION tag's energy and/or committed transmission reservation(s) profile may be reduced to reflect a desire to flow less energy or commit less transmission than originally requested. Reductions are used to indicate cancellations and terminations, as well as partial decreases. **Combinations of 1.1, 1.2, and 1.3 may be submitted concurrently.** **Coordination responsibilities of the PURCHASING-SELLING ENTITY.** The modification must be provided by the PURCHASING-SELLING ENTITY to the following INTERCHANGE TRANSACTION participants: • Generation Providing Entity • • • TRANSMISSIONCUSTOMERS • Scheduling Entities (INTERMEDIARY CONTROL AREAS) • Intermediate PURCHASING-SELLING ENTITIES (Title-holders) •			

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
• LOAD-SERVING ENTITY • Market Redispatch Notification Entities (if specified)			
1.6 INTERCHANGE TRANSACTION modification confirmation. Depending on the type of change, certain entities must evaluate and approve or deny the INTERCHANGE TRANSACTION modification. The following tables illustrate the entities required to evaluate the modification and the criteria they should use in their evaluation. All other entities will be notified of the request. Net Increases in Committed Transmission Reservations or changes in Loss Provision- TSP and DC Tie operator Net Decreases in Committed Transmission Reservations – TSP and DC tie operator Increases in Energy Flow- BA's , TSP's, RA and DC tie operator Decreases in Energy Flow- BA's , TSP's, RA and DC tie operator	**Standard Reference-** Included in Coordinate Interchange Standard Requirement 402 measures.	**Covered under NAESB CI Std** under Req. 8.1.2	
1.7 INTERCHANGE TRANSACTION modification and evaluation time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in Section D of **Appendix 3A1, "Tag Submission and Evaluation Timetable."**	None	**Covered under the NAESB CI Std** under Req. 4.1, 5.0	There will not be any timing requirements in the reliability standard. If the tag is not submitted in time the deal does not happen.
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Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
2. INTERCHANGE TRANSACTION modification for reliability-related issues. A RELIABILITY AUTHORITY, TRANSMISSION PROVIDER, GENERATION CONTROL AREA, or LOAD CONTROL AREA may modify an INTERCHANGE TRANSACTION Tag that is in progress or scheduled to be started**.** These modifications may be made *only* due to TLR events (or other regional congestion management practices), Loss of Generation, or Loss of Load.	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		
2.1 Assignment of coordination responsibilities during TLR events. At such times when TLR is required to ensure reliable operation of the electrical system, and the TLR requires holding or curtailing INTERCHANGE TRANSACTIONS, the LOAD CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags. See **Policy 9, Appendix 9C1 "Transmission Loading Relief Procedure."** **2.1.1 Reductions**. When a RELIABILITY AUTHORITY must curtail or hold an INTERCHANGE TRANSACTION to respect TRANSMISSION SERVICE reservation priorities or to mitigate potential or actual OPERATING SECURITY LIMIT violations, the RELIABILITY AUTHORITY shall inform the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the greatest reliable level at which the affected	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		The IA is responsible for the coordination of these actions

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
INTERCHANGE TRANSACTION may flow. **2.1.2 Reloads.** At such time as the TLR event allows for the reloading of the transaction, the RELIABILITY AUTHORITY shall inform the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the releasing of the INTERCHANGE TRANSACTION'S limit.			
2.2 Coordination when implementing other congestion management procedures. As a part of some local and regional congestion management and transmission line overload procedures, the TRANSMISSION PROVIDER is responsible for implementing curtailment of INTERCHANGE TRANSACTIONS. The TRANSMISSION PROVIDER may adjust the INTERCHANGE TRANSACTION tags as required to implement those local and regional congestion management or transmission overload relief procedures that have been approved by the Region(s) or NERC. **2.2.1 Reductions.** When a TRANSMISSION PROVIDER experiences the need to invoke a congestion management or transmission line overload procedure, it may use the curtailment feature of E-Tag to inform the GENERATION CONTROL AREA and the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the greatest reliability limit at which the affected	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		The transmission provider will notify the Reliability Coordinator of the need for a curtailment. The IA is responsible for the coordination of these actions

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
INTERCHANGE TRANSACTION may flow. **2.2.2 Reloads.** At such time as the need for the congestion management or transmission line overload relief procedure allows for the full or partial reloading of the transaction, the TRANSMISSION PROVIDER may use the reload feature of E-Tag to inform the GENERATION CONTROL AREA and the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag that the INTERCHANGE TRANSACTION'S reliability limit has changed.			
2.3 Assignment of coordination responsibilities during a loss of generation. At such times when a loss of generation necessitates curtailing INTERCHANGE TRANSACTIONS, the Generation CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags. **2.3.1 Reductions.** When a generation operator experiences a full or partial loss of generation, it shall notify the HOST CONTROL AREA (the generation CONTROL AREA for the INTERCHANGE TRANSACTION). The HOST CONTROL AREA contacts the Generation Providing Entity that is responsible for the generation. The Generation Providing Entity determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals are required.		The BA will notify the Reliability Coordinator of the need for a curtailment. The IA is responsible for the coordination of these actions

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
extensions (either via the Tag Author, or directly if the Entity is the Tag Author or a Market Operator). If the Generation Providing Entity does not resolve the condition, the HOST CONTROL AREA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the generation. **2.3.2 Reloads.** Upon return of the generation, the generator operator shall notify the HOST CONTROL AREA (the Generation CONTROL AREA for the INTERCHANGE TRANSACTION). The HOST CONTROL AREA contacts the Generation Providing Entity that is responsible for the generation. The Generation providing Entity determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the Tag Author, or directly if the Entity is the Tag Author or a Market Operator). The HOST CONTROL AREA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the generation (but not override any market-based reductions).			
2.4 Assignment of coordination responsibilities during a loss of load. At such times when a loss of load necessitates curtailing INTERCHANGE TRANSACTIONS, the LOAD CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION	Included in Coordinate Interchange Standard Requirement 402 Measure vii (1): For a reliability related change requested by a Reliability Authority, no other entity approvals		The BA will notify the Reliability Coordinator of the need for a curtailment. The IA is responsible for the coordination of these actions

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Tags. **2.4.1 Reductions.** When a LOAD-SERVING ENTITY experiences a loss of load, it shall notify its HOST CONTROL AREA (the LOAD CONTROL AREA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via the Tag Author, or directly if the Entity is the Tag Author or a Market Operator). If the LOAD-SERVING ENTITY does not notify the HOST CONTROL AREA, the HOST CONTROL AREA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the load. **2.4.2 Reloads.** Upon return of the load, THE LOAD-SERVING ENTITY shall notify its HOST CONTROL AREA (the LOAD CONTROL AREA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via the Tag Author, or directly if the Entity is the Tag Author or a Market Operator). If the LOAD-SERVING ENTITY does not notify the HOST CONTROL AREA, the HOST CONTROL AREA must release the limits previously imposed on	are required.		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
INTERCHANGE TRANSACTIONS associated with the load (but not override any market-based reductions).			
2.5 Coordination responsibilities of the requesting CONTROL AREA. The modification must be provided by the Requesting CONTROL AREA to the following INTERCHANGE TRANSACTION participants: Transmission Customers Scheduling Entities (INTERMEDIATE CONTROL AREAS) Intermediate PURCHASING-SELLING ENTITIES (Title-holders) LOAD-SERVING ENTITY Generation Providing Entity Generation CONTROL AREA TRANSMISSION PROVIDERS Load CONTROL AREA Market Redispatch Notification Entities (if specified) Security Analysis Services	Included in Coordinate Interchange Standard Requirement 404: The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange.”	**Under the NAESB CI Std** under Req. 6.0	The IA will coordinate and notify all entities of changes.
2.6 INTERCHANGE TRANSACTION modification confirmation. Reliability-based modifications must be evaluated and confirmed prior to implementation. The following table illustrates the entities required to evaluate and the criteria they should use in their evaluation. All other entities will be notified of the request.	Included in Coordinate Interchange Standard Requirement 403: The Reliability Authority, Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to		

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Generation Control Area- Energy profile (ability of generation to accommodate) DC Tie Operating Transmission Providers or Control Areas- Energy profile (ability of tie to accommodate) Load Control Area- Energy profile (ability of load to accommodate)	transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.		
2.7 INTERCHANGE TRANSACTION modification and evaluation time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in **Appendix 3A1, "Tag Submission and Evaluation Timetable."**	None	**Covered under NAESB CI Std** under Req. 4.1 and 5.0	There will not be any timing requirements in the reliability standard. If the tag is not submitted in time the deal does not happen.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Section C			
1. INTERCHANGE SCHEDULE start and end time. INTERCHANGE SCHEDULES shall begin and end at a time agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA, and the INTERMEDIARY CONTROL AREAS. **2. Ramp start times.** CONTROL AREAS shall ramp the INTERCHANGE equally across the start and end times of the schedule. **3.Ramp duration.** CONTROL AREAS shall use the ramp duration established by their INTERCONNECTION as follows unless they agree otherwise: **3.1 INTERCHANGE SCHEDULES within the Eastern and ERCOT INTERCONNECTIONS.** ten-minute ramp duration. **3.2 INTERCHANGE SCHEDULES within the Western INTERCONNECTION.** 20-minute ramp duration. **3.3 INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary.** The CONTROL AREAS that implement INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary must use the same start time and ramp durations.	Included in Coordinate Interchange Standard Requirement 402 measures.	**Covered under NAESB CI Std** under Req. 12.0	The standard does provide or preclude standard ramp times for the Eastern and Western Interconnection.
3.4 Exceptions for Compliance with Disturbance Control Standard and Line Load Relief. Ramp durations for INTERCHANGE SCHEDULES implemented for compliance with NERC's Disturbance	None		The standard does not have a specific ramp requirement.

Policy Requirement	Coordinate Interchange Standard Reference	NAESB Reference	Comments
Control Standard (recovery from a disturbance condition) and INTERCHANGE TRANSACTION curtailment in response to line loading relief procedures may be shorter, but must be identical for the SENDING CONTROL AREA and RECEIVING CONTROL AREA **[See also Policy1E2, "Generation Control Performance – Performance Standard."]**			
4. INTERCHANGE SCHEDULE accounting. Block accounting shall be used.	None	**Covered under NAESB CI Std** under Req. 10.0	

Item 10. Other Subcommittee Items – Gordon Scott

Background

Scheduling Agent E-Tag Fields

Doug Hils will report on conversation with GridAmerica.

Item 11. Future Meetings – Secretary

Identify agenda Items for the June 16–18, 2004 Interchange Subcommittee meeting in Toronto.

Attachment

11a Calendar for 2004

2004 Interchange Subcommittee Meetings

2004 Dates	Location
April 21 – 23	San Diego, California
June 16 – 18	Toronto, Canada
September 13 – 15	Boston, Massachusetts
November 30 – December 2	Ft. Lauderdale, Florida