NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Agenda
Board of Trustees

October 29, 2008 | 8–11 a.m.
The Westin Arlington Gateway
801 North Glebe Road
Arlington, Virginia
703-717-6200

Introductions and Chairman's Remarks

Antitrust Compliance Guidelines

Consent Agenda — Approve

*1. **Minutes**
- June 24, 2008 Action Without a Meeting
- July 15, 2008 Conference Call
- July 30, 2008 Meeting
- August 8, 2008 Action Without a Meeting
- August 26, 2008 Conference Call
- September 8, 2008 Action Without a Meeting
- September 29, 2008 Action Without a Meeting

*2. **Standing Committees**
   a. Committee Membership Appointments and Changes
   b. Revisions to Committee Charters

*3. **Future Meetings**

Regular Agenda

4. **President's Report**

*5. **Reliability Standards**
   a. Reliability Standards Development Plan: 2009–2011
   b. Standards Errata and Errata Procedure
   c. Project 2007-14 — Permanent Changes to Coordinate Interchange Timing Tables

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Princeton, NJ 08540
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   d. Status of Standards Development
   e. WECC Tier 1 Standards

*6. **Recommendations from Corporate Governance and Human Resources Committee on Standards Process**

*7. **Transmission Availability Data System Phase II Reporting Requirements and Timetable**

Committee, Group, and Forum Reports (Item 8)

Compliance and Certification Committee

Critical Infrastructure Protection Committee

Member Representatives Committee

Operating Committee

Personnel Certification Governance Committee

Planning Committee

Regional Entity Management Group

Standards Committee

Transmission Owners and Operators Forum

Board Committee Reports

9. **Finance and Audit**

10. **Nominating Committee**

11. **Compliance**

12. **Corporate Governance and Human Resources**

13. **Technology**

14. **Other Business**

* Background materials included

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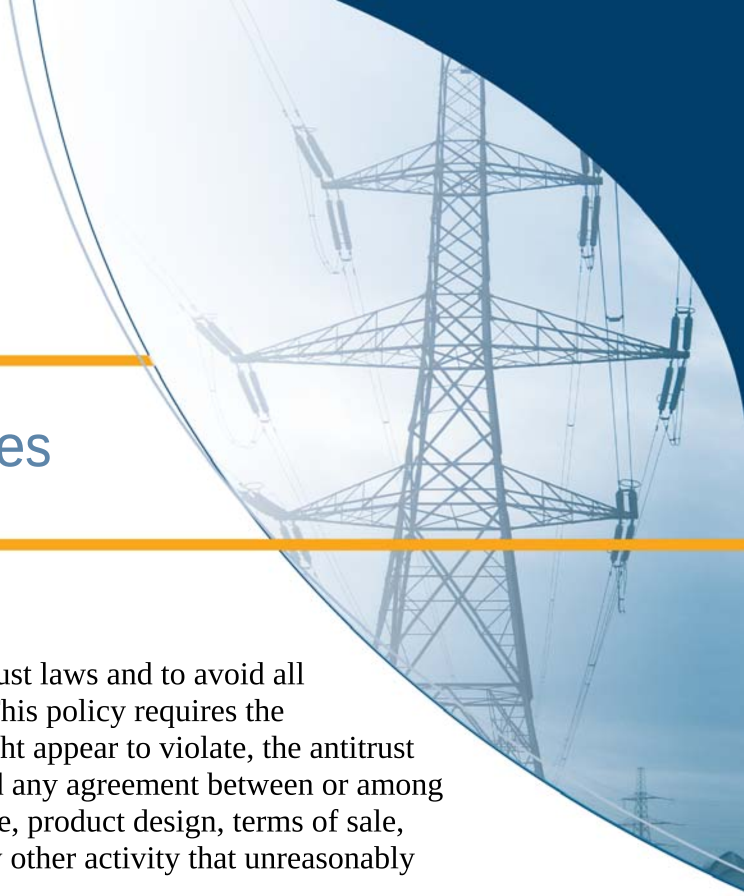


Antitrust Compliance Guidelines

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

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.

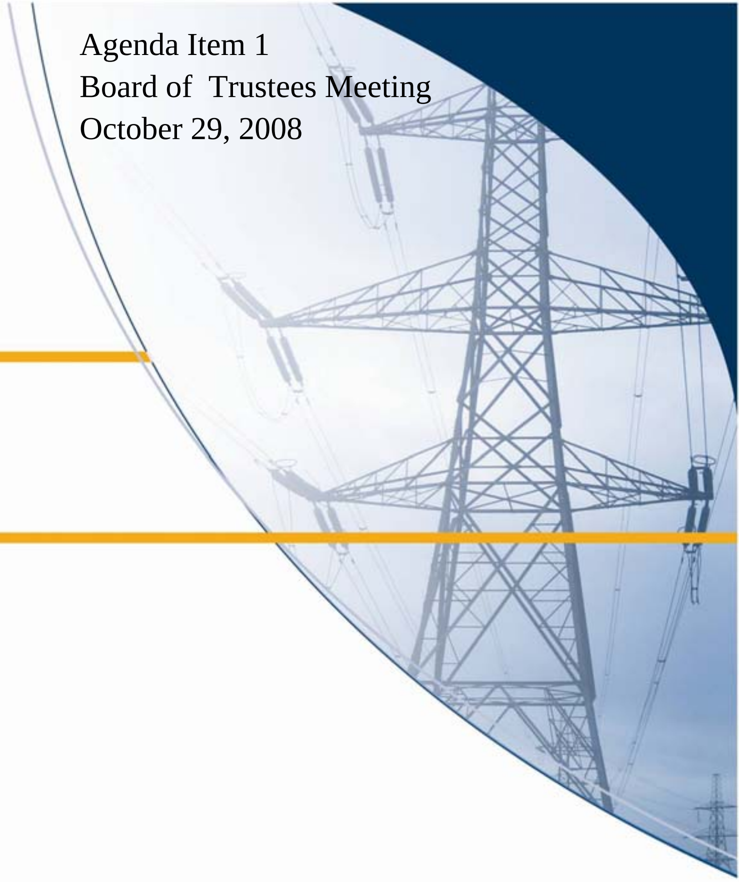
You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the 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.



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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Draft Minutes
Board of Trustees

Action Without a Meeting
June 24, 2008

On June 24, 2008, a majority of the members of the Board of Trustees of the North American Electric Reliability Corporation consented in writing to waive notice and take action without a meeting, and approved revised Reliability Standards FAC-010-2, FAC-011-2, and FAC-014-2.

Attached to these minutes are the memorandum (**Exhibit A**) from the General Counsel requesting the vote and the written votes of a majority of the trustees (**Exhibit B**).

Submitted by,

Secretary

Draft Minutes
Board of Trustees

July 15, 2008 | 11 a.m.
Conference Call

Pursuant to notice duly given, Chairman Richard Drouin called to order an open meeting by conference call of the Board of Trustees of the North American Electric Reliability Corporation on July 15, 2008, at 11 a.m., EDT. As required by the bylaws of the Corporation, dial-in listen-only access was provided to members of the Corporation and the public for the meeting. The notice, agenda, and background material for the meeting are attached as **Exhibits A, B and C** respectively.

Trustees present on the call in addition to Chairman Drouin were John Q. Anderson, Paul Barber, Tom Berry, Janice Case, James Goodrich, Fred Gorbet, Sharon Nelson, Ken Peterson, and Bruce Scherr. Also present on the call were David Whiteley, Gerry Adamski, Dave Nevius, Julia Souder, and David Cook of the NERC staff.

David Cook called attention to the Antitrust Compliance Guidelines included with the agenda package.

Compliance Filing for March 21 FERC Order

David Cook presented the proposed compliance filing in response to FERC's March 21, 2008 order conditionally approving the revised delegation agreements and related material. After discussion, on motion of Fred Gorbet, the board approved the draft compliance filing, substantially in the form presented as part of the agenda package, to include the following elements:

(1) Explanatory statement;
(2) Revised *pro forma* delegation agreement;
(3) Revised Appendix 4C to Rules of Procedure (Compliance Monitoring and Enforcement Program and Attachments 1 and 2);
(4) Amendments to Rules 202, 313, 401, 402, 403, 404, 501, 804, 805, 1106, and 1501 of the NERC Rules of Procedure;
(5) Revised delegation agreements for the eight regional entities:
   a. Florida Reliability Coordinating Council
   b. Midwest Reliability Organization
   c. Northeast Power Coordinating Council
   d. Reliability*First* Corporation
   e. SERC Electric Reliability Corporation

f. Southwest Power Pool (including the proposed amendments to the SPP bylaws that are to be approved by the SPP board and membership)
g. Texas Regional Entity, a division of ERCOT
h. Western Electricity Coordinating Council (including the proposed amendments to the WECC bylaws that are to be approved by the WECC board)

Board members are to call or email David Cook with any suggested edits or language changes.

Second Anniversary Compliance Filing

David Cook presented the draft second anniversary compliance filing on programs to enhance reliability that had been circulated to the board with the agenda package. In view of the July 11, 2008, decision of the Finance and Audit Committee regarding the reliability readiness evaluation program, the draft will be revised to delete references to that program. Trustees asked that material relating to NERC's increased emphasis on cyber security matters be added to the draft. Trustees also asked that the draft accurately track the proposed 2009 business plan and budget regarding the North American SynchroPhasor Initiative. Following further discussion, on motion of Tom Berry, the board approved the second anniversary compliance filing, with the modifications discussed during the meeting.

Request for Clarification and Rehearing of FERC's June 19 Order Regarding Violation Severity Levels

David Cook presented the draft request for clarification and rehearing of FERC's June 19 order regarding violation severity levels, in the form circulated to board members on July 14, 2008. After consideration, on motion of Paul Barber, the board approved filing the request for clarification and rehearing.

Appointment of Chair and MRC Representatives to BOT Nominating Committee

On motion of Ken Peterson, the board appointed Fred Gorbet as chair of the Nominating Committee for this year. On motion of Ken Peterson, the board appointed six representatives proposed by the Member Representatives Committee to serve on the Nominating Committee for this year (Steve Hickok, Steve Naumann, William Gallagher, Jean-Paul Theoret, John A. Anderson, and Michael Desselle).

There being no other business, Chairman Drouin terminated the conference call at 11:20 a.m., EDT.

Submitted by,

David N. Cook

David N. Cook
Secretary

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft Minutes
Board of Trustees

July 30, 2008 | 8 a.m.–noon
Hyatt Regency
1255 Jeanne-Mance Street
Montréal, Québec
514-982-1234

Chairman Richard Drouin called to order a duly noticed meeting of the North American Electric Reliability Corporation Board of Trustees on July 30, 2008 at 8 a.m., local time, and a quorum was declared present. The meeting announcement, agenda, and list of attendees are attached as **Exhibits A**, **B**, and **C**, respectively.

NERC Antitrust Compliance Guidelines
David Cook, vice president and general counsel, directed participants' attention to the NERC Antitrust Compliance Guidelines included in the agenda.

Executive Session
Chairman Drouin reported that, as is its custom, the board met in executive session before the open meeting, without the chief executive officer present, to review management activities. The board also had a security-related briefing from Joseph McClelland, Director of FERC's Office of Electric Reliability, in closed session.

Minutes
The board approved the following draft minutes (**Exhibit D**):

- May 7, 2008 Meeting

Future Meetings
The board approved August 4–5, 2009 in Winnipeg, Manitoba, Canada as a future meeting date and location.

President's Report
President and CEO Rick Sergel described how NERC was being challenged in the reliability sphere by action in three other spheres: safety, costs, and environment.

- Safety. The lesson learned from the safety arena is that we must be relentless in pursuing zero tolerance as the only acceptable outcome. Those dealing with safety issues were striving for zero lost-time incidents. We must do the equivalent for reliability.
- Costs. Today we will present a budget that is significantly lower and reflects input from the Finance and Audit Committee and commenters. We have retained those resources we deem to be essential in maintaining standards and compliance. It is a practical budget with the most notable changes made to the readiness program. The fundamental change that has taken place in the organization, from voluntary to enforceable standards, makes it much more difficult to run a readiness program. It raises the question of whether someone else is better able to do the job.
- Environment: We plan to address to what extent NERC as an organization has to take on the responsibility of the impact of the environment on reliability in the Long Term Reliability Assessment. We must be prepared to understand what it takes to run a system, to use the resources we have, to be successful in nuclear, and we need to step into the transmission discussion — but we will not become political. We need it to be very aggressive in understanding what the impacts are. NERC is in an international role at the highest level, and we intend to use the LTRA to focus on what the most important reliability actions are. We are going to take on those issues across the board. Reliability — it's what we do.

Mr. Sergel also highlighted the reliability accomplishments to date:

- The Compliance Registry clearly identifies the users, owners, and operators of the bulk power system that are subject to the Reliability Standards.
- The Reliability Standards continue to evolve and improve, and we continue to have strong volunteer technical expertise in the process.
- The enforcement process is working, because it is improving reliability. The focus on vegetation management is drawing us all to look carefully at that issue and make improvements. We need to carry that same focus over to other areas, such as relays. It provides us with an opportunity to improve performance.
- We have an increased cyber security focus.
- We have improved our communications, with a new web site and an "alerts" procedure for getting important information out to the users, owners, and operators.

Events Analysis

Bob Cummings, director of NERC's Events Analysis & Information Exchange Program, presented the findings and recommendations from the event analysis of the August 4, 2007 Eastern Interconnection Frequency Disturbance. He also presented an overview of the industry alerts that will be issued by NERC as a result of that analysis to help improve system reliability. Potential alerts stemming from the MRO Disturbance of September 18, 2007 were also highlighted (**Exhibit E**).

Electricity Sector Steering Group Charter

David Whiteley, executive vice president, reported on the status of the Electricity Sector Steering Group (ESSG) and presented its charter (**Exhibit F**) for approval. Following discussion, on motion by Rick Sergel, the board approved the following resolution:

RESOLVED, that the Board of Trustees takes the following actions:

(1) Approves the proposed charter of the Electricity Sector Steering Group (ESSG), revised to incorporate the changes discussed during the meeting.

(2) Appoints Janice Case as the NERC independent trustee member of the ESSG.

(3) Ratifies the June 30, 2008 vote of the Member Representatives Committee to select the following CEO-level representatives of NERC member organizations as members of the ESSG:

Paul Murphy, CEO, Ontario IESO (2 year term)
Jim Torgerson, CEO, UIL Holdings (2 year term)
Ken Ksionek, CEO, Orlando Utilities (2 year term)
Gary Fulks, General Manager, Sho-Me Power (1 year term)
Paul Bonavia, Utilities Group President, Xcel Energy (1 year term)

Amendments to NERC Bylaws

David Cook presented the proposed amendments to the NERC Bylaws (**Exhibit G**). He reported the MRC had approved the proposed amendments at its July 29, 2008 meeting. Mr. Cook stated it is NERC's intention, upon approval by the board, to file promptly with FERC so the bylaws will be in effect by fall for the Nominating Committee process. On motion of Sharon Nelson, the board approved the following resolution:

WHEREAS, the Corporate Governance and Human Resources Committee of the NERC Board of Trustees has recommended that the NERC Bylaws be amended in the manner set forth in the proposed amendments to the Bylaws included under Tab 6 of the July 30, 2008 Board agenda;

WHEREAS, on July 29, 2008 the Member Representatives Committee approved the amendments to the Bylaws in the manner proposed; and

WHEREAS, the Board of Trustees desires to amend the Bylaws in the manner proposed;

"RESOLVED, that the NERC Board of Trustees approves the proposed amendments to the NERC Bylaws and directs that they be filed with applicable governmental authorities in the United States and Canada."

Transmission Owners and Operators Forum Charter Revision

Jose Delgado, Transmission Owners and Operators Forum (Forum) Chairman, presented revisions to the Forum Charter for approval that would get as much diversity in the organization as possible without compromising the policies of the Forum. In response to a question noting that *NERC's 2009 Business Plan and Budget* does not include the reliability readiness program, Mr. Delgado stated that the Forum follows the INPO (Institute for Nuclear Power Operations) model of peer reviews. The Forum expects to do one such review this year and learn from it; the number of peer reviews will grow over time. Following further questions and discussion among the trustees, on motion of Rick Sergel, the board approved the following resolution:

> WHEREAS, on May 21, 2008 the Steering Committee of the Transmission Owners and Operators Forum ("Forum") agreed to modify Section 3 of the Forum's charter regarding membership eligibility requirements to extend the opportunity to those organizations who own or operate at least 50 circuit miles of transmission lines at 100 kV or greater (formerly 200 miles), or operate a "24/7" transmission control center with NERC-certified transmission or reliability operators (new), or have an open access transmission tariff or equivalent on file with a regulatory authority (no change);
>
> WHEREAS, the Forum's charter was approved by the Board of Trustees on November 1, 2006, pursuant to the authority of Rule 712 of NERC's Rules of Procedure; and
>
> WHEREAS, the NERC Board of Trustees desires to make the changes proposed in the Forum's charter;
>
> "RESOLVED, that the Board of Trustees approves the proposed changes in Section 3 of the Forum's charter, as follows:
>
> 2. Eligibility for Membership. Membership in the Forum shall be open to any person or entity that owns, operates or controls at least ~~200~~ 50 circuit miles of integrated transmission facilities, or continuously operates a control center staffed by NERC-certified Transmission Operators[1], or has an open access transmission tariff or equivalent on file with a regulatory authority; provided, however, that Members also must be members of NERC. Members may include, without limitation, regional transmission organizations and independent system operators."
>
> 1 NERC defines the credentials for Transmission Operators and Reliability Operators as part of NERC's System Operator Certification Program.

Reliability Standards

- Gerry Adamski, director of standards, gave a presentation (**Exhibit H**) on the Reliability Standards before the board for approval. Following questions and discussion among the trustees, on motion by Fred Gorbet, the board approved the following resolution:

"RESOLVED, that the Board of Trustees approves the following reliability-related standards matters and directs that they be filed with applicable governmental authorities:

(a) Nine Missing Violation Risk Factors for Cyber Security Standards, as set forth in the table below:

Standard	Requirement	Requirement Text	Violation Risk Factor
CIP-002-1	R3.1.	The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,	**LOWER**
CIP-003-1	R4.1.	The Critical Cyber Asset information to be protected shall include, at a minimum and regardless of media type, operational procedures, lists as required in Standard CIP-002, network topology or similar diagrams, floor plans of computing centers that contain Critical Cyber Assets, equipment layouts of Critical Cyber Assets, disaster recovery plans, incident response plans, and security configuration information.	**LOWER**
CIP-003-1	R5.1.2.	The list of personnel responsible for authorizing access to protected information shall be verified at least annually.	**LOWER**
CIP-004-1	R2.2.2.	Physical and electronic access controls to Critical Cyber Assets;	**LOWER**
CIP-004-1	R2.2.3.	The proper handling of Critical Cyber Asset information; and,	**LOWER**
CIP-005-1	R1.5.	Cyber Assets used in the access control and monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003, Standard CIP-004 Requirement R3, Standard CIP-005 Requirements R2 and R3, Standard CIP-006 Requirements R2 and R3, Standard CIP-007, Requirements R1 and R3 through R9, Standard CIP-008, and Standard CIP-009.	**LOWER**
CIP-007-1	R5.1.	The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.	**LOWER**
CIP-007-1	R5.3.3	Each password shall be changed at least annually, or more frequently based on risk.	**LOWER**
CIP-007-1	R7.	Disposal or Redeployment — The Responsible Entity shall establish formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005.	**LOWER**

(b) Proposed interpretation of requirements R1.3.2 and R1.3.12 in standard TPL-002-0, System Performance Following Loss of a Single BES Element;

(c) Proposed interpretation of requirements R1.3.2 and R1.3.12 in standard TPL-003-0, System Performance Following Loss of Two or More BES Elements."

Revised Registration Criteria

David Hilt, director of compliance and organization certification, presented for approval the NERC Statement of Compliance Registry Criteria Revision 5.0 Version 2. (**Exhibit I**).

On motion by Paul Barber, the board approved the following resolution:

> "RESOLVED, that the Board of Trustees approves the Statement of Compliance Registry Criteria, Revision 5.0, Version 2, in the form included in the board agenda package under Tab 9 and directs that the revision be filed with the Federal Energy Regulatory Commission."

Board of Trustees Task Force Reports

Readiness Evaluation and Improvement Program

Bruce Scherr, Finance and Audit Committee Chairman, reported on the committee's review of the future of the Readiness Evaluation and Improvement Program. Based upon the committee's review of the 12 sets of comments received in response to version 2 of the *2009 Business Plan and Budget*, which included comments by the NERC Operating Committee and several Regional Entities directly addressing the readiness issue, the committee determined the readiness program has run its course as a NERC program and has provided direction to phase out the program. Given this direction, the current version of the budget shows that the readiness evaluation program will complete its remaining scheduled readiness evaluations and close in early 2009.

Standards Process Program

Sharon Nelson reported on the Corporate Governance and Human Resources Committee's review of the standards process. A work plan to deliver initial recommendations to the board by the October 29, 2008 meeting has been discussed and Ms. Nelson reported the committee would be initially focusing attention on three high-priority, short-term issues: how the compliance elements of standards should be developed and approved; what NERC's process for developing standards in an emergency situation, especially for cyber security, should be; and what NERC's relationship with FERC regarding the reliability standard approval process should be.

David Nevius, senior vice president and director of reliability assessment and performance analysis, and Gerry Adamski will update and distribute to all committee members, and other participants, revised Issue Summaries for these three issues. The committee will be divided into three subgroups, along with other participants, to focus on one issue each. Each subgroup will meet by conference call to discuss their respective Issue Summaries, which will then be coordinated and sent to the rest of the committee members and other participants for review and comment. Mid-September and early-October conference calls are planned to review and discuss comments and to agree on final recommendations to be presented to the board at the October 29, 2008 meeting.

Compliance Program
Paul Barber, Board of Trustees Compliance Committee Chairman, reported on the committee's review of the compliance program. The committee's deliberations were focused on questions of policy, procedure, and process collected from the board and regional executives in response to a letter from Rick Sergel. These questions were separated into five areas and subdivided into short-, medium-, and long-term time horizons. NERC staff was directed to develop an initial draft work plan based upon discussion by the committee. The committee reviewed this work plan at their July 29, 2008 meeting.

NERC Critical Infrastructure Protection Strategic Direction and Capability
Rick Sergel thanked all who reviewed the draft of his July 7th, 2008 letter to the Board of Trustees and NERC Stakeholders on NERC's Critical Infrastructure Protection Strategic Direction and Capability (**Exhibit J**). He stated it is his intent to move forward on each of the recommendations given in the letter as well as filling the position of Chief Security Officer. The cyber security conference with CEOs is scheduled for September 23 in Washington. David Cook will send a copy of the draft legislation FERC has proposed to give FERC additional authority to deal with cyber security threats.

Compliance Monitoring and Enforcement
David Hilt gave a presentation on the status of the Compliance Monitoring and Enforcement (**Exhibit K**).

Committee, Group, and Forum Reports

Compliance and Certification Committee
Chairman Tom Abrams reported the committee is working on several program documents which serve as the platform for the CCC's monitoring program and address the CCC charter mission statement. In addition, they have developed program documents outlining processes related to the Rules of Procedure.

Critical Infrastructure Protection Committee
Chairman Barry Lawson reported the committee is currently working to finalize the guideline on CIP-002, to support the standard. This will be developed under the new guideline procedure and will go to the standards committee for additional guidance. He added the committee is looking forward to working with the ESSG and participating in their discussions, including participating in the cyber security summit. Mr. Lawson stated the committee will continue to work with NERC staff and other standing committee chairs to help reduce costs and will hold CIPC's December meeting in the NRECA office. He informed the board that Robert Canada, CIPC Vice-Chairman, is not present today due to attending the Critical Infrastructure Protection Advisory Committee annual meeting of the Department of Homeland Security. This is a public meeting for all 18 critical infrastructures where discussion is held on what has happened during the last year.

Member Representatives Committee
Chairman Steve Hickok stated he and Steve Naumann, MRC Vice Chairman, will work with Rick Sergel and David Whiteley on how to sequence the new meeting structure. Mr. Hickok announced the October meeting would be his last as an officer of the MRC and he will conduct the orientation session for the new MRC members in February, prior to the MRC meeting.

Operating Committee
Chair Gayle Mayo stated the committee's primary focus has been on the readiness program. The committee is working to reduce meeting costs and continuing to look at operational reliability trends.

Planning Committee
Chairman Scott Helyer reported the committee is continuing to improve the reliability assessments. He has scheduled the following items to be discussed at the September meeting: the reliability assessments handbook; the working group's progress on metrics; definitions currently being used; and budget and meeting costs.

Regional Entity Management Group
Chairman Dan Skaar began his report by thanking the NERC staff for their work on the budget and recommended the approval of the Regional Entity budgets. He stated the U.S.-Canadian matters underscore the important work that has been completed and the work that still needs to be done. He added the international nature of NERC's work is important.

Standards Committee
Chairman Scott Henry stated that in response to Mr. Sergel's letter, the SC is forming a drafting team to review changes to the CIP standards and the committee will work closely with the board task force regarding the letter's request for an expedited standards process. He explained the existing process has an urgent action process and an emergency action process. The industry is fully committed to an industry-based standards process and comments have been favorable to the board interaction with the standards process. The SC meets on a monthly basis and is ready to take action in between meetings as needed. He added that the committee has organized itself to be as responsive as possible.

NAESB
Michael Desselle stated an effort is underway to develop business practices for more flexible gas and electric timelines, but it is failing to gather a supermajority. Gas deliverability is a component that needs to be factored into the LTRA while Demand Response should take a two-prong approach. He added, NERC needs to be involved in the wholesale quadrant. NAESB is working with NERC on the development of their survey and working on reliability and the ATC standards, to be completed and filed in the next order. On July 21, 2008 FERC approved a number of Version 1 business practice standards including OASIS and also approved a new standard on TLR interconnection.

Transmission Owners and Operators Forum

Jose Delgado, Forum Chairman, stated the Forum's budget is part of NERC's budget and that they intend to hire two additional employees in the coming year. The Forum is currently working on cyber issues.

Board Committee Reports

Finance and Audit Committee

Bruce Scherr gave the report from the Finance and Audit Committee. On the recommendation of the committee, the board approved the 2nd Quarter Statement of Activities.

On motion by Bruce Scherr, the board approved the following resolution with respect to the 2009 business plans and budgets of NERC and the eight Regional Entities:

RESOLVED,

(1) that the Board of Trustees approves the following, substantially in the form presented:

(a) the proposed NERC 2009 business plan and budget;

(b) the proposed 2009 business plans and budgets of the eight regional entities;

(c) the proposed 2009 budget request of the Western Interconnection Regional Advisory Body;

(d) the preliminary proposed 2009 assessments to recover the costs of the approved 2009 budgets, on the condition that the board will approve the final 2009 assessments in writing without a meeting prior to their being filed with applicable governmental authorities.

(2) that management is directed to file the 2009 business plans and budgets with FERC and governmental authorities in Canada, together with such additional explanatory material as is appropriate.

Mr. Scherr also reported on proposed revisions to the NERC Policy on Allocation of Certain Compliance and Enforcement Costs to deal with the pending agreement with the Régie in Québec. On motion of Mr. Scherr, the board adopted the following resolution:

RESOLVED, that on recommendation of the Finance and Audit Committee, the Board of Trustees approves the proposed Expanded Policy on Allocation of Certain Compliance and Enforcement Costs.

Compliance Committee
Chairman Paul Barber reported the committee continues its monthly review of CMEP and notices of penalties and settlements. The committee is discussing delegating authority over certain matters to the staff.

Corporate Governance and Human Resources Committee
Sharon Nelson reported for the committee on behalf of Committee Chairman John Q. Anderson. The committee recommends adoption of a revised conflict of interest and business ethics policy for NERC trustees, officers and employees. On motion of Sharon Nelson the board approved the revised conflict of interest and business ethics policy as set out in **Exhibit L**. The committee also recommends adoption of a 457(b) plan for supplemental deferred compensation for executives for whom contributions to the defined contribution portion of NERC's 401(k) plan are limited by the federal tax code. On motion by Sharon Nelson, the board adopted the following resolution:

> WHEREAS, the Corporate Governance and Human Resources Committee has recommended that NERC establish a supplemental non-qualified deferred compensation plan for executives for whom contributions to the defined contribution portion of NERC's 401(k) plan are limited by the federal tax code;
>
> WHEREAS, the Board of Trustees deems it desirable and in NERC's best interests to establish such a plan; and
>
> WHEREAS, it is the intent of the Board of Trustees that the plan meet the requirements of the Internal Revenue Code of 1986, as amended, and the regulations adopted thereunder;
>
> RESOLVED, that the appropriate officers of NERC are hereby authorized and directed to take any and all actions, and execute such documents, as may be necessary to establish a Section 457(b) non-qualified deferred compensation plan for NERC.

Technology Committee
Jim Goodrich reported the Technology Committee has been following NERC's role in the NASPI project and a member of the committee will be attending the NASPI meeting to be held later in the day. The committee is also looking to schedule a meeting at Oak Ridge National Lab in the fall.

Adjournment
There being no further business, Chairman Drouin terminated the meeting at 11:00 a.m.

Submitted by,

D M Cook

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Draft Minutes
Board of Trustees

Action Without a Meeting
August 8, 2008

On August 8, 2008, a majority of the members of the Board of Trustees of the North American Electric Reliability Corporation consented in writing to waive notice and take action without a meeting, and approved the proposed 2009 assessments to Load Serving Entities and other entities.

Attached to these minutes are the memorandum from the General Counsel requesting the vote and the written votes of a majority of the trustees as **Exhibits A and B** respectively.

Submitted by,

David N. Cook

Secretary

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft Minutes
Board of Trustees

August 26, 2008 | 11 a.m.
Conference Call

Pursuant to notice duly given, Chairman Richard Drouin called to order an open meeting by conference call of the Board of Trustees of the North American Electric Reliability Corporation on August 26, 2008, at 11 a.m., EDT. As required by the bylaws of the Corporation, dial-in listen-only access was provided to members of the Corporation and the public for the meeting. The notice, agenda, and participant list are attached as **Exhibit A, B, and C** respectively.

Trustees present on the call in addition to Chairman Drouin were Paul Barber, Tom Berry, Janice Case, James Goodrich, Fred Gorbet, Ken Peterson, Rick Sergel, and Bruce Scherr. Also present on the call were Gerry Adamski, David Hilt, and Rebecca Michael, of the NERC staff.

Assistant General Counsel Rebecca Michael called attention to the Antitrust Compliance Guidelines included with the agenda package.

Available Transfer Capability Standards

Gerry Adamski presented the request for approval of Reliability Standards associated with Available Transfer Capability. He reported all five standards had achieved the required 75 percent quorum requirement and 66-2/3 percent affirmative vote in the recently concluded recirculation ballot. He responded to questions and observations from a number of board members on various aspects of the standards and the filing to be made. Board members expressed their appreciation for the tremendous amount of work done on the project by the standards drafting team and industry participants. After extended discussion among board members, on motion of Rick Sergel, the board took the following actions:

(1) Approved the following Reliability Standards:
MOD-001-1 — Available Transmission System Capability
MOD-008-1 — TRM Calculation Methodology
MOD-028-1 — Area Interchange Methodology
MOD-029-1 — Rated System Path Methodology
MOD-030-1 — Flowgate Methodology

(2) Approved the definitions of 18 new and 2 revised terms for inclusion in the NERC Glossary of Terms, as follows:

> ATC Path, Available Transfer Capability, Available Transfer Capability Implementation Document (ATCID), Transmission Operator Area, Existing Transmission Commitments (ETC), Planning Coordinator, Postback, Business Practices, Block Dispatch, Dispatch Order, Participation Factors, Transmission Reliability Margin Implementation Document (TRMID), Area Interchange Methodology, Rated System Path Methodology, Flowgate, Total Flowgate Capability (TFC), Available Flowgate Capability (AFC), Power Transfer Distribution Factor (PTDF), Outage Transfer Distribution Factor (OTDF), and Flowgate Methodology.

(3) Approved the retirement of the following Reliability Standard, to take effect when the Reliability Standards approved in paragraph (1) above become effective:

FAC-013-1 — Establish and Communicate Transfer Capabilities

(4) Approved the withdrawal of the request for approval of the following Reliability Standards that the Commission did not approve or remand in Order No. 693 because these standards are wholly superseded by those approved in paragraph (1) above:

FAC-012-1 — Transfer Capability Methodology
MOD-001-0 — Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies
MOD-002-0 — Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results
MOD-003-0 — Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values
MOD-008-0 — Documentation and Content of Each Regional Transmission Reliability Margin Methodology
MOD-009-0 — Procedure for Verifying Transmission Reliability Margin Values

(5) Remanded to the Standards Committee the Violation Risk Factors associated with the Reliability Standards approved in paragraph (1) above to provide an opportunity for further evaluation and description of the direct impact of the standards on the bulk power system.

Compliance and Certification Committee Program Documents

David Hilt presented three program documents written by the Compliance and Certification Committee (CCC) to address various aspects of its monitoring function.

- The first document addresses how the CCC will audit NERC to verify adherence with the Rules of Procedure for compliance enforcement.
- The second document describes how the CCC will collect information and make assessments of NERC's compliance with applicable reliability standards.
- The third document addresses how the CCC will monitor and assess NERC's adherence to its Reliability Standards Development Procedure

Following questions and discussion by board members, on motion of Paul Barber, the board approved the three program documents.

There being no other business, Chairman Drouin terminated the conference call at 11:55 a.m., EDT.

Submitted by,

Rebecca Michael

Rebecca Michael
Assistant General Counsel
Acting Secretary

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Draft Minutes
Board of Trustees

Action Without a Meeting
September 8, 2008

On September 8, 2008, a majority of the members of the Board of Trustees of the North American Electric Reliability Corporation consented in writing to waive notice and take action without a meeting, and adopted a resolution approving NERC's Special Reliability Assessment, entitled "*2008-2017 NERC Capacity Margins: Retrofit of Once-Through Cooling Systems at Existing Generating Facilities.*

Attached to these minutes are the memorandum from the General Counsel requesting the vote and the written votes of a majority of the trustees as **Exhibits A and B** respectively.

Submitted by,

Secretary

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Draft Minutes
Board of Trustees

Action Without a Meeting
September 29, 2008

On September 29, 2008, a majority of the members of the Board of Trustees of the North American Electric Reliability Corporation consented in writing to waive notice and take action without a meeting, and adopted a resolution approving a proposed revision to Exhibit E of the delegation agreement between NERC and the Western Electricity Coordinating Council.

Attached to these minutes are the memorandum from the General Counsel requesting the vote and the written votes of a majority of the trustees as **Exhibits A and B** respectively.

Submitted by,

David N. Cook

Secretary

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Committee Membership Appointments and Changes

Board Action Required
Approve the following changes

Compliance and Certification Committee
ISO/RTO — Matthew F. Goldberg, Director, Reliability and Operations Compliance, ISO New England Inc.

Agenda Item 2b
Board of Trustees Meeting
October 29, 2008

Revisions to Committee Charters

Board Action Required

Approve changes to the charters of the NERC Operating and Planning Committees.

Information

Operating Committee Charter Revisions

The recommended revisions to the Operating Committee Charter (**Attachment 1**) approved by the Operating Committee on September 10, 2008 are summarized below:

Section 1. Functions

- **Approve the following documents and procedures:** added: "The technical content of the…."

Section 2. Membership

- **Expectations:** added: "Inform the secretary of any changes in their status that may affect their eligibility for committee membership. Failure to do so in a timely manner may result in the member's dismissal by the chairman."
- **Representation:** added: "A non-voting representative must meet the requirements defined in Appendix 1. Voting members, with the exception of sector 11 that appoints its members, may hold a position in any sector in which they would be eligible for NERC membership, even if they are a NERC member in another sector. Questions regarding eligibility for committee membership will be referred to the NERC general counsel for final determination of status."
- **Selection:** added: "With the exception of sector 11,…to…."
- **Terms:** added: "…cases described below"…." "Shorter terms may be required for several reasons:
  a. If two members are simultaneously selected to a sector that did not have any existing members, in order to stagger their terms, one member will be assigned a one-year term and the second member will be assigned a two-year term using a fair and unbiased method.
  b. If a member replaces a departed member between elections, the new member will assume the remaining term of the departed member.
  c. If a member fills a vacant member position between elections, his/her term will end when the term for that vacant position ends."
- **Resignations, Vacancies, and Nonparticipation:** added **"**The chairman may remove any member who has missed two consecutive meetings (even with a proxy)."
- **Proxies:** added:
  a. "Meets the member's eligibility requirements (see Section 2.3a) and is not affiliated with the same organization as another committee member (see Section 2.4c), or
  b. Is not another committee member, unless that committee member would represent the proxy's sector instead of his/her own sector at the meeting.

To permit time to determine a proxy's eligibility, proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable). Any proxy submitted after that time will be accepted at the chairman's discretion, provided that the chairman believes the proxy meets the eligibility requirements."

Section 3. Meetings

- **Voting:** added: "Except for sector 11, each voting member of the committee shall have one vote on any matter coming before the committee that requires a vote. Sector 11 voting is specified in Appendix 1."

Planning Committee Charter Revisions

The recommended revisions to the Planning Committee Charter (**Attachment 2**) approved by the Planning Committee on September 10, 2008 are summarized below:

- **Removal of members**: The charter gives the chair the discretion to remove members as described in Section 3.2.g and Section 3.6.e.
- **Requirements for membership**: The charter clarifies the qualifications required for a committee member to hold a position in a sector in Section 3.3.a.
- **Terms**: Terms are two years and are staggered. However, Section 3.5 has additional language describing when shorter terms are appropriate.
- **Proxies**: Section 3.7 has new language with regard to proxies.

Attachment 1

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Operating Committee Charter

to ensure the reliability of the bulk power system

September 10, 2008

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Table of Contents

Purpose

The Operating Committee's mission is to provide the ERO (stakeholders, Board of Trustees, and staff) with the collective and diverse opinions from the experts in interconnected systems operation to help the industry arrive at informed decisions.

Section 1. Functions

1. **General forum.** Provides a general forum for aggregating ideas and interests regarding the operations of the interconnected bulk power systems in North America.

2. **Advice and recommendations.** Provides NERC (stakeholders, Board of Trustees, and staff) with advice, recommendations, and the collective and diverse opinions on matters related to interconnected operations to help the industry arrive at informed decisions. Issue reliability guidelines in accordance with the process described in Appendix 3.

3. **Support to the Reliability Readiness Program.** Provide technical support, guidance, and advice to NERC's Reliability Readiness Program (see also NERC Rules of Procedure, Section 700, "Reliability Readiness Evaluation and Improvement program, and Appendix 7, "Reliability Readiness Evaluation and Improvement Program Procedure").

a. **General**

- Develop criteria for measuring program success, and review the program against those criteria.
- Recommend actions to other NERC programs (standards, compliance, assessments, training, etc.) based on lessons learned and trends from readiness evaluations and examples of excellence.

b. **Readiness Evaluations**

- Review readiness evaluations for trends and recommend new or different types of evaluations or changes in processes or metrics, including:
    - Readiness criteria
    - Guidelines for reporting and disclosure, and
    - Guidelines for consistency and relevancy of evaluations:
        - Between comparable entities, and
        - Through time
- Provide guidance to the readiness evaluations process.

c. **Examples of Excellence**

- Review and discuss the examples of excellence for lessons learned
- Support information exchange within the industry on examples of excellence

4. **Support for other programs.** Provide technical advice and subject matter expert support to each of the NERC program areas, and serve as a forum to integrate the outputs of each NERC program area.

   a. **Standards**.

   - **Provide opinions.** Provide the committee's majority and minority opinions to the industry on NERC's standards as those standards are drafted, posted for ballot, and presented to the board of trustees for implementation.
   - **Help prioritize standards**. Help the Standards Committee prioritize those standards that are in the drafting queue.

   b. **Compliance**. Review quarterly and annual compliance reports for trends and suggest new or different types of compliance monitoring based on a technical review of system performance trends or as a result of compliance investigations.

   c. **Reliability assessments and performance analysis**. Review reliability assessments and recommend topics that need additional investigation. These include:

   - Future adequacy
   - Event analysis
   - Benchmarking

   d. **Personnel training and certification**. Recommend to the Personnel Certification Governance Committee the types of operating personnel that should be certified.

   e. **Situation awareness**. Review and recommend control, monitoring, and visualization tools for system operators.

5. **Approve the following documents and procedures:**

   a. Reliability Coordinator plans.

   b. Market operations plans that are a part of the Reliability Coordinator plans.

   c. Field test procedures, and the commencement and end of field tests to make sure those tests are "safe and effective."

   d. The technical content of the NERC Reliability Functional Model.

6. **Opinions and interpretations.** Provide technical opinions at the industry stakeholders' request on operating reliability concepts, philosophies, and standards.

Section 2. Membership

1. **Goals** The Operating Committee provides for balanced decision making by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in the area of interconnected systems operation reliability.

2. **Expectations.** Operating Committee voting members are expected to:

   a. Bring subject matter expertise to the Operating Committee

   b. Be responsible for operating reliability within their organization

c. Attend and participate in all Operating Committee meetings

d. Express their own opinions, as well as the opinions of the sector they represent, at committee meetings

e. Discuss and debate interests rather than positions

f. Complete committee assignments

g. Inform the secretary of any changes in their status that may affect their eligibility for committee membership. Failure to do so in a timely manner may result in the member's dismissal by the chairman.

3. **Representation.** See Appendix 1, "Committee Members"

a. Committee members may, but need not be, NERC members. A non-voting representative must meet the requirements defined in Appendix 1. Voting members, with the exception of sector 11 that appoints its members, may hold a position in any sector in which they would be eligible for NERC membership, even if they are a NERC member in another sector. Questions regarding eligibility for committee membership will be referred to the NERC general counsel for final determination of status.

b. To ensure adequate Canadian representation, the membership to the committee may be increased so that the number of Canadian voting members is equal to the percentage of the net energy for load (NEL) of Canada to the total NEL of the United States and Canada, times the total number of voting members on the committee, rounded to the next whole number.

4. **Selection.** With the exception of sector 11, NERC sector members will annually elect voting committee members to committee sectors corresponding to their NERC sector under an election process that is open, inclusive, and fair. The selection process will be completed in time for the secretary to send the committee membership list to the board for its approval at the board's August meeting so that new committee members may be seated at the September meeting.

a. Un-nominated voting member positions will remain vacant until the next annual election, or until the committee secretary receives a nomination for that position, whichever occurs first.

b. Members may not represent more than one committee sector.

c. A particular organization, including its affiliates, may not have more than one member on the committee.

d. If additional Canadian members are added, no more than one additional Canadian voting member shall be selected from a sector unless this limitation precludes the addition of the number of additional Canadian voting representatives required by Section 2.3.b. In this case, no more than two additional Canadian voting members may be selected from the same sector.

e. The secretary will monitor the committee selection process to insure that membership specifications are met.

5. **Terms.** Members' terms are staggered, with one-half of the members' terms expiring each year. Except for the cases described below, a member's term is two years and will commence on the first September meeting following the member's selection pursuant to Section 2.4 and continue until the September meeting two years later. Members may be re-elected for subsequent terms. Shorter terms may be required for several reasons:

   a. If two members are simultaneously selected to a sector that did not have any existing members, in order to stagger their terms, one member will be assigned a one-year term and the second member will be assigned a two-year term using a fair and unbiased method.

   b. If a member replaces a departed member between elections, the new member will assume the remaining term of the departed member.

   c. If a member fills a vacant member position between elections, his/her term will end when the term for that vacant position ends.

6. **Resignations, Vacancies, and Nonparticipation**

   a. Members who resign will be replaced for the time remaining in the member's term. Members will be replaced pursuant to Section 2.4, officers will be replaced pursuant to Section 4, and executive committee members will be replaced pursuant to Section 6.

   b. The secretary will submit the new member's name to the board for approval at the board's next regular meeting.

   c. The committee may approve the new member on an interim basis at the committee's next meeting.

   d. The committee chairman will contact any member who has missed two consecutive meetings (even if the member has sent a proxy) to 1) seek a commitment to actively participate or 2) ask the member to resign from the committee.

   e. The chairman may remove any member who has missed two consecutive meetings (even with a proxy).

7. **Proxies.** A member of the committee may give a proxy only to a person who:

   a. Meets the member's eligibility requirements (see Section 2.3a) and is not affiliated with the same organization as another committee member (see Section 2.4c), or

   b. Is not another committee member, unless that committee member would represent the proxy's sector instead of his/her own sector at the meeting.

   To permit time to determine a proxy's eligibility, proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable). Any proxy submitted after that time will be accepted at the chairman's discretion, provided that the chairman believes the proxy meets the eligibility requirements.

Section 3. Meetings

See Appendix 2, “Meeting Procedures.” Unless stated otherwise, the Operating Committee will follow Roberts Rules of Order, Newly Revised.

1. **Quorum.** The quorum necessary for the transaction of business (i.e., formal actions) at meetings of the Committee is two-thirds of the voting members currently on the committee roster (i.e., does not count vacancies). The committee may engage in discussions without a quorum present.

2. **Voting.** Except for sector 11, each voting member of the committee shall have one vote on any matter coming before the committee that requires a vote. Sector 11 voting is specified in Appendix 1.Actions by members of the Committee shall be approved upon receipt of the affirmative vote of 2/3 of the voting members of the Committee present and voting, in person or by proxy, at any meeting at which a quorum is present. The chairman and vice chairman may vote. Additional voting guidelines are in Appendix 2.

3. **Antitrust Guidelines.** All persons attending or otherwise participating in the Committee meeting shall act in accordance with NERC’s Antitrust Compliance Guidelines at all times during the meeting. A copy of the NERC antitrust statement shall be included with each meeting agenda.

4. **Open Meetings.** NERC committee meetings shall be open to the public, except as noted below under Confidential Sessions. Although meetings are open, only voting members may offer and act on motions.

5. **Confidential Sessions.** The chairman of a committee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties. A preference, where possible, is to avoid the disclosure of sensitive or confidential information so that meetings may remain open at all times. Confidentiality agreements may also be applied as necessary to protect sensitive information.

Section 4. Officers

1. **Terms and conditions.** At its June meeting the Committee shall select a chairman and vice chairman from among its voting members by majority vote of the members of the Committee to serve during the period July 1 through June 30 of the following two years, provided that:

   a. The newly selected chairman and vice chairman shall not be representatives of the same sector.

   b. The chairman and vice chairman, upon assuming such positions, shall cease to act as representatives of the sectors that elected them as representatives to the Committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

   c. The secretary will submit the elected officers to the chairman of the board for approval.

2. **Selection.** The Committee selects officers using the following process. The chairman is selected first, followed by the vice chairman.

1. The nominating subcommittee will present its recommended candidate.
2. The chairman opens the floor for nominations.
3. After hearing no further nominations, the chairman closes the nominating process.
4. The Committee will then vote on the candidate recommended by the nominating subcommittee, followed by the candidates nominated from the floor in the order in which they were nominated. The first candidate to garner the majority of the Committee's votes will be selected.
5. If the Committee nominates one person, that person is automatically selected as the next chairman.
6. If the Committee nominates two or more persons, and none receive a majority of the Committee's votes, then the secretary will distribute paper ballots for the members to mark their preference.
7. The secretary will collect the ballots. If the Committee nominates three or more candidates, then the winner will be selected using the Instant Runoff Process. (Explained in Roberts Rules of Order)

Section 5. Subcommittees

1. **Appointing subgroups.** The Operating Committee may appoint technical subcommittees, task forces, and working groups as needed.

2. **Nominating subcommittee.** At the first regular meeting following the selection of a new committee chairman, the chairman will nominate, for the committee's approval, a slate of five committee members from different sectors to serve as a nominating subcommittee. The subcommittee will:

a. Recommend candidates for the committee's chairman and vice chairman, and
b. Recommend candidates for the executive committee's four "at large" members.

Section 6. Executive Committee

1. **Authorization.** The executive committee is authorized to act between regular meetings of its parent committee. However, the executive committees may not reverse its parent committee's decisions.

2. **Membership.** The Committee will elect an executive committee of six members, all from different sectors, as follows:

- Chairman

- Vice-chairman
- Four at-large members from different sectors nominated by the nominating subcommittee.

3. **Election Process.**The Nominating Subcommittee will present its slate of candidates for the four “at large” members.

- The chairman opens the floor for additional nominations.
- If the Committee members nominate additional candidates, then the secretary will distribute paper ballots for the members to list their top four candidates.
- The four candidates who receive the most votes will be elected, provided that no two candidates may be from the same sector.

4. **Terms.** The executive committee will be replaced every two years, with the chairman and vice chairman replaced at a June meeting and the at-large members replaced at a September meeting.

Appendix 1 – Committee Members

Name	Definition	Members
Voting Members		
1. Investor-owned utility	This sector includes any investor-owned entity with substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission, or distribution. This sector also includes organizations that represent the interests of such entities.	2
2. State/municipal utility	This sector includes any entity owned by or subject to the governmental authority of a state or municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state or municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating, transmitting, or purchasing electricity for sale at wholesale to their members. This sector also includes organizations that represent the interests of such entities.	2
3. Cooperative utility	This sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities. This sector also includes organizations that represent the interests of such entities.	2
4. Federal or provincial utility/Federal Power Marketing Administration	This sector includes any U.S. federal, Canadian provincial, or Mexican entity that owns and/or operates electric facilities in any of the asset categories of generation, transmission, or distribution; or that functions as a power marketer or power marketing administrator. This sector also includes organizations that represent the interests of such entities. One member will be a U.S. federal entity and one will be a Canadian provincial entity.	2
5. Transmission dependent utility	This sector includes any entity with a regulatory, contractual, or other legal obligation to serve wholesale aggregators or customers or end-use customers and that depends primarily on the transmission systems of third parties to provide this service. This sector also includes organizations that represent the interests of such entities.	2
6. Merchant electricity generator	This sector includes any entity that owns or operates an electricity generating facility that is not included in an investor-owned utility's rate base and that does not otherwise fall within any of sectors (i) through (v). This sector includes but is not limited to cogenerators, small power producers, and all other non-utility electricity producers such as exempt wholesale generators who sell electricity at wholesale. This sector also includes organizations that represent the interests of such entities.	2
7. Electricity marketer	This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.	2

<table>
<tr><th>Name</th><th colspan="3">Definition</th><th>Members</th></tr>
<tr><td colspan="5">Voting Members</td></tr>
<tr><td>8. Large end-use electricity customer</td><td colspan="3">This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.</td><td>2</td></tr>
<tr><td>9. Small end-use electricity customer</td><td colspan="3">This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.</td><td>2</td></tr>
<tr><td>10. Independent system operator/regional transmission organization</td><td colspan="3">This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.</td><td>2</td></tr>
<tr><td rowspan="10">11. Regional reliability organization</td><td colspan="3">This sector includes any regional reliability organization as defined in Article I, Section 1, of the Bylaws of the corporation. In aggregate, this sector will have voting strength equivalent to two members. The voting weight of each regional member’s vote will be set such that the sum of the weight of all available regional reliability organizations members’ votes is two votes.</td><td rowspan="10">2</td></tr>
<tr><td><u>RRO</u></td><td><u>Number of Members</u></td><td><u>Proportional Voting</u></td></tr>
<tr><td>FRCC</td><td>1</td><td>X</td></tr>
<tr><td>RFC</td><td>1</td><td>X</td></tr>
<tr><td>ERCOT</td><td>1</td><td>X</td></tr>
<tr><td>MRO</td><td>1</td><td>X</td></tr>
<tr><td>NPCC</td><td>1</td><td>X</td></tr>
<tr><td>SERC</td><td>1</td><td>X</td></tr>
<tr><td>SPP</td><td>1</td><td>X</td></tr>
<tr><td>WECC</td><td>1</td><td>X</td></tr>
<tr><td>12. State government</td><td colspan="3">(See Government representatives below)</td><td>2</td></tr>
<tr><td>Officers</td><td colspan="3">Chairman and Vice Chairman</td><td>2</td></tr>
<tr><td colspan="4" align="right">Total Voting Members</td><td>26</td></tr>
</table>

Name	Definition	Members
Non-Voting Members[1]		
Government representatives	This sector includes any federal, state, or provincial government department or agency in North America having a regulatory and/or policy interest in wholesale electricity. Entities with regulatory oversight over the Corporation or any regional entity, including U.S., Canadian, and Mexican federal agencies and any provincial entity in Canada having statutory oversight over the Corporation or a regional entity with respect to the approval and/or enforcement of reliability standards, may be nonvoting members of this sector.	
	United States federal government	2
	Canadian federal government	1
	Provincial government	1
Secretary	The committee secretary will be seated at the committee table	1
Subcommittee Chairmen	The chairmen of the subcommittees will be seated at the committee table.	

[1] Industry associations and organizations and other government agencies in the U.S. and Canada may attend meetings as non-voting observers.

Appendix 2 – Meeting Procedures

Section 1. Voting Procedures for Motions

1. The default procedure is a voice vote.

2. If the chairman believes the voice vote is not conclusive, he may call for a show of hands.

3. The chairman will not specifically ask those who are abstaining to identify themselves when voting by voice or a show of hands.

4. The committee may conduct a roll-call vote in those situations that need a record of each member's vote.

    - The committee must approve conducting a roll call vote for the motion.
    - The secretary will call each member's name.
    - Members answer "yes," "no," or "present" if they wish to abstain from voting.

Section 2. Minutes

1. Meeting minutes are a record of what the committee did, not what its members said.

2. Minutes should list discussion points where appropriate, but should usually not attribute comments to individuals. It is acceptable to cite the chairman's directions, summaries, and assignments.

3. Do not list the person who seconds a motion.

4. Do not record (or even ask for) abstentions.

Section 3. Minority Opinions

All Committees members are afforded the opportunity to provide alternative views on an issue. The meeting minutes will provide an exhibit to record minority opinions. The chairman shall report both the majority and any minority views in presenting results to the Board of Trustees.

Section 4. Personal Statements

The minutes will also provide an exhibit to record personal statements.

Appendix 3 – Reliability Guidelines Approval Process

1. Reliability Guidelines
   Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.[2]

2. Approval of Reliability Guidelines
   Because reliability guidelines contain suggestions that may result in actions by responsible entities, those suggestions must be thoroughly vetted before a new or updated guideline receives approval by a technical committee. The process described below will be followed by the Operating Committee:

   a. New/updated draft guideline approved. The Operating Committee approves release of a new or updated draft guideline developed by one of its subgroups or the committee as a whole.

   b. Post draft guideline for industry comment. The draft guideline is posted for industry-wide comment for forty-five (45) days. If the draft guideline is an update, a redline version against the previous version must also be posted.

   c. Post industry comments and responses. After the public comment period, the Operating Committee posts the comments received as well as its responses to the comments. The committee may delegate the preparation of responses to a committee subgroup.

   d. New/updated guideline approval and posting. A new or updated guideline which considers the comments received, is approved by the sponsoring technical committee and posted on the NERC Web site. Updates must include a revision history and a redline version against the previous version.

   e. Guideline updates. After posting a new or updated guideline, the Operating Committee will continue to accept comments from the industry via a Web-based forum where commenters may post their comments.

      i. Each quarter, the Operating Committee will review the comments received. At any time, the Operating Committee may decide to update the guideline based on the comments received or on changes in the industry that necessitate an update.

      ii. Updating an existing guideline will require that a draft updated guideline be approved by the Operating Committee in step “a” and proceed to steps “b” and “c” until it is approved by the Operating Committee in step “d.”

[2] Standards Committee authorization is required for a reliability guideline to become a supporting document that is posted with or referenced from a NERC Reliability Standard. See Appendix 3A in the NERC’s *Rules of Procedure* under “Supporting Documents.”

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Operating Committee Charter

Draft: August 15, 2008

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to ensure the reliability of the bulk power system

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Purpose

The Operating Committee's mission is to provide the ERO (stakeholders, Board of Trustees, and staff) with the collective and diverse opinions from the experts in interconnected systems operation to help the industry arrive at informed decisions.

Section 1. Functions

1. **General forum.** Provides a general forum for aggregating ideas and interests regarding the operations of the interconnected bulk power systems in North America.

2. **Advice and recommendations.** Provides NERC (stakeholders, Board of Trustees, and staff) with advice, recommendations, and the collective and diverse opinions on matters related to interconnected operations to help the industry arrive at informed decisions. Issue reliability guidelines in accordance with the process described in Appendix 3.

3. **Support to the Reliability Readiness Program.** Provide technical support, guidance, and advice to NERC's Reliability Readiness Program (see also NERC Rules of Procedure, Section 700, "Reliability Readiness Evaluation and Improvement program, and Appendix 7, "Reliability Readiness Evaluation and Improvement Program Procedure").

   a. **General**

   - Develop criteria for measuring program success, and review the program against those criteria.
   - Recommend actions to other NERC programs (standards, compliance, assessments, training, etc.) based on lessons learned and trends from readiness evaluations and examples of excellence.

   b. **Readiness Evaluations**

   - Review readiness evaluations for trends and recommend new or different types of evaluations or changes in processes or metrics, including:
     - Readiness criteria
     - Guidelines for reporting and disclosure, and
     - Guidelines for consistency and relevancy of evaluations:
       - Between comparable entities, and
       - Through time
   - Provide guidance to the readiness evaluations process.

   c. **Examples of Excellence**

   - Review and discuss the examples of excellence for lessons learned
   - Support information exchange within the industry on examples of excellence

4. **Support for other programs.** Provide technical advice and subject matter expert support to each of the NERC program areas, and serve as a forum to integrate the outputs of each NERC program area.

   a. **Standards**.

   - **Provide opinions.** Provide the committee's majority and minority opinions to the industry on NERC's standards as those standards are drafted, posted for ballot, and presented to the board of trustees for implementation.
   - **Help prioritize standards**. Help the Standards Committee prioritize those standards that are in the drafting queue.

   b. **Compliance**. Review quarterly and annual compliance reports for trends and suggest new or different types of compliance monitoring based on a technical review of system performance trends or as a result of compliance investigations.

   c. **Reliability assessments and performance analysis**. Review reliability assessments and recommend topics that need additional investigation. These include:

   - Future adequacy
   - Event analysis
   - Benchmarking

   d. **Personnel training and certification**. Recommend to the Personnel Certification Governance Committee the types of operating personnel that should be certified.

   e. **Situation awareness**. Review and recommend control, monitoring, and visualization tools for system operators.

5. **Approve the following documents and procedures:**

   a. Reliability Coordinator plans.

   b. Market operations plans that are a part of the Reliability Coordinator plans.

   c. Field test procedures, and the commencement and end of field tests to make sure those tests are "safe and effective."

   d. The technical content of the NERC Reliability Functional Model.

6. **Opinions and interpretations.** Provide technical opinions at the industry stakeholders' request on operating reliability concepts, philosophies, and standards.

Section 2. Membership

1. **Goals** The Operating Committee provides for balanced decision making by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in the area of interconnected systems operation reliability.

2. **Expectations.** Operating Committee voting members are expected to:

   a. Bring subject matter expertise to the Operating Committee

   b. Be responsible for operating reliability within their organization

c. Attend and participate in all Operating Committee meetings

d. Express their own opinions, as well as the opinions of the sector they represent, at committee meetings

e. Discuss and debate interests rather than positions

f. Complete committee assignments

g. Inform the secretary of any changes in their status that may affect their eligibility for committee membership. Failure to do so in a timely manner may result in the member's dismissal by the chairman.

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3. **Representation.** See Appendix 1, "Committee Members"

a. Committee members may, but need not be, NERC members. A non-voting representative must meet the requirements defined in Appendix 1. Voting members, with the exception of sector 11 that appoints its members, may hold a position in any sector in which they would be eligible for NERC membership, even if they are a NERC member in another sector. Questions regarding eligibility for committee membership will be referred to the NERC general counsel for final determination of status.

b. To ensure adequate Canadian representation, the membership to the committee may be increased so that the number of Canadian voting members is equal to the percentage of the net energy for load (NEL) of Canada to the total NEL of the United States and Canada, times the total number of voting members on the committee, rounded to the next whole number.

4. **Selection.** With the exception of sector 11, NERC sector members will annually elect voting committee members to committee sectors corresponding to their NERC sector under an election process that is open, inclusive, and fair. The selection process will be completed in time for the secretary to send the committee membership list to the board for its approval at the board's August meeting so that new committee members may be seated at the September meeting.

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a. Un-nominated voting member positions will remain vacant until the next annual election, or until the committee secretary receives a nomination for that position, whichever occurs first.

b. Members may not represent more than one committee sector.

c. A particular organization, including its affiliates, may not have more than one member on the committee.

d. If additional Canadian members are added, no more than one additional Canadian voting member shall be selected from a sector unless this limitation precludes the addition of the number of additional Canadian voting representatives required by Section 2.3.b. In this case, no more than two additional Canadian voting members may be selected from the same sector.

e. The secretary will monitor the committee selection process to insure that membership specifications are met.

5. **Terms.** Members' terms are staggered, with one-half of the members' terms expiring each year. Except for the cases described below, a member's term is two years and will commence on the first September meeting following the member's selection pursuant to Section 2.4 and continue until the September meeting two years later. Members may be re-elected for subsequent terms. Shorter terms may be required for several reasons:

   a. If two members are simultaneously selected to a sector that did not have any existing members, in order to stagger their terms, one member will be assigned a one-year term and the second member will be assigned a two-year term using a fair and unbiased method.

   b. If a member replaces a departed member between elections, the new member will assume the remaining term of the departed member.

   c. If a member fills a vacant member position between elections, his/her term will end when the term for that vacant position ends.

6. **Resignations, Vacancies, and Nonparticipation**

   a. Members who resign will be replaced for the time remaining in the member's term. Members will be replaced pursuant to Section 2.4, officers will be replaced pursuant to Section 4, and executive committee members will be replaced pursuant to Section 6.

   b. The secretary will submit the new member's name to the board for approval at the board's next regular meeting.

   c. The committee may approve the new member on an interim basis at the committee's next meeting.

   d. The committee chairman will contact any member who has missed two consecutive meetings (even if the member has sent a proxy) to 1) seek a commitment to actively participate or 2) ask the member to resign from the committee.

   e. The chairman may remove any member who has missed two consecutive meetings (even with a proxy).

7. **Proxies.** A member of the committee may give a proxy only to a person who:

   a. Meets the member's eligibility requirements (see Section 2.3a) and is not affiliated with the same organization as another committee member (see Section 2.4c), or

   b. Is not another committee member, unless that committee member would represent the proxy's sector instead of his/her own sector at the meeting.

   To permit time to determine a proxy's eligibility, proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable). Any proxy submitted after that time will be accepted at the chairman's discretion, provided that the chairman believes the proxy meets the eligibility requirements.

Section 3. Meetings

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See Appendix 2, "Meeting Procedures. " Unless stated otherwise, the Operating Committee will follow Roberts Rules of Order, Newly Revised.

1. **Quorum.** The quorum necessary for the transaction of business (i.e., formal actions) at meetings of the Committee is two-thirds of the voting members currently on the committee roster (i.e., does not count vacancies). The committee may engage in discussions without a quorum present.

2. **Voting.** Except for sector 11, each voting member of the committee shall have one vote on any matter coming before the committee that requires a vote. Sector 11 voting is specified in Appendix 1.Actions by members of the Committee shall be approved upon receipt of the affirmative vote of 2/3 of the voting members of the Committee present and voting, in person or by proxy, at any meeting at which a quorum is present. The chairman and vice chairman may vote. Additional voting guidelines are in Appendix 2.

3. **Antitrust Guidelines.** All persons attending or otherwise participating in the Committee meeting shall act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting. A copy of the NERC antitrust statement shall be included with each meeting agenda.

4. **Open Meetings.** NERC committee meetings shall be open to the public, except as noted below under Confidential Sessions. Although meetings are open, only voting members may offer and act on motions.

5. **Confidential Sessions.** The chairman of a committee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties. A preference, where possible, is to avoid the disclosure of sensitive or confidential information so that meetings may remain open at all times. Confidentiality agreements may also be applied as necessary to protect sensitive information.

Section 4. Officers

1. **Terms and conditions.** At its June meeting the Committee shall select a chairman and vice chairman from among its voting members by majority vote of the members of the Committee to serve during the period July 1 through June 30 of the following two years, provided that:

    a. The newly selected chairman and vice chairman shall not be representatives of the same sector.

    b. The chairman and vice chairman, upon assuming such positions, shall cease to act as representatives of the sectors that elected them as representatives to the Committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

    c. The secretary will submit the elected officers to the chairman of the board for approval.

2. **Selection.** The Committee selects officers using the following process. The chairman is selected first, followed by the vice chairman.

1. The nominating subcommittee will present its recommended candidate.
2. The chairman opens the floor for nominations.
3. After hearing no further nominations, the chairman closes the nominating process.
4. The Committee will then vote on the candidate recommended by the nominating subcommittee, followed by the candidates nominated from the floor in the order in which they were nominated. The first candidate to garner the majority of the Committee's votes will be selected.
5. If the Committee nominates one person, that person is automatically selected as the next chairman.
6. If the Committee nominates two or more persons, and none receive a majority of the Committee's votes, then the secretary will distribute paper ballots for the members to mark their preference.
7. The secretary will collect the ballots. If the Committee nominates three or more candidates, then the winner will be selected using the Instant Runoff Process. (Explained in Roberts Rules of Order)

Section 5. Subcommittees

1. **Appointing subgroups.** The Operating Committee may appoint technical subcommittees, task forces, and working groups as needed.

2. **Nominating subcommittee.** At the first regular meeting following the selection of a new committee chairman, the chairman will nominate, for the committee's approval, a slate of five committee members from different sectors to serve as a nominating subcommittee. The subcommittee will:

a. Recommend candidates for the committee's chairman and vice chairman, and
b. Recommend candidates for the executive committee's four "at large" members.

Section 6. Executive Committee

1. **Authorization.** The executive committee is authorized to act between regular meetings of its parent committee. However, the executive committees may not reverse its parent committee's decisions.

2. **Membership.** The Committee will elect an executive committee of six members, all from different sectors, as follows:

- Chairman

- Vice-chairman
- Four at-large members from different sectors nominated by the nominating subcommittee.

3. **Election Process.**The Nominating Subcommittee will present its slate of candidates for the four "at large" members.

- The chairman opens the floor for additional nominations.
- If the Committee members nominate additional candidates, then the secretary will distribute paper ballots for the members to list their top four candidates.
- The four candidates who receive the most votes will be elected, provided that no two candidates may be from the same sector.

4. **Terms.** The executive committee will be replaced every two years, with the chairman and vice chairman replaced at a June meeting and the at-large members replaced at a September meeting.

Appendix 1 – Committee Members

Name	Definition	Members
Voting Members		
1. Investor-owned utility	This sector includes any investor-owned entity with substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission, or distribution. This sector also includes organizations that represent the interests of such entities.	2
2. State/municipal utility	This sector includes any entity owned by or subject to the governmental authority of a state or municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state or municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating, transmitting, or purchasing electricity for sale at wholesale to their members. This sector also includes organizations that represent the interests of such entities.	2
3. Cooperative utility	This sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities. This sector also includes organizations that represent the interests of such entities.	2
4. Federal or provincial utility/Federal Power Marketing Administration	This sector includes any U.S. federal, Canadian provincial, or Mexican entity that owns and/or operates electric facilities in any of the asset categories of generation, transmission, or distribution; or that functions as a power marketer or power marketing administrator. This sector also includes organizations that represent the interests of such entities. One member will be a U.S. federal entity and one will be a Canadian provincial entity.	2
5. Transmission dependent utility	This sector includes any entity with a regulatory, contractual, or other legal obligation to serve wholesale aggregators or customers or end-use customers and that depends primarily on the transmission systems of third parties to provide this service. This sector also includes organizations that represent the interests of such entities.	2
6. Merchant electricity generator	This sector includes any entity that owns or operates an electricity generating facility that is not included in an investor-owned utility's rate base and that does not otherwise fall within any of sectors (i) through (v). This sector includes but is not limited to cogenerators, small power producers, and all other non-utility electricity producers such as exempt wholesale generators who sell electricity at wholesale. This sector also includes organizations that represent the interests of such entities.	2
7. Electricity marketer	This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.	2

<table>
<tr><th>Name</th><th colspan="3">Definition</th><th>Members</th></tr>
<tr><td colspan="5">Voting Members</td></tr>
<tr><td>8. Large end-use electricity customer</td><td colspan="3">This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.</td><td>2</td></tr>
<tr><td>9. Small end-use electricity customer</td><td colspan="3">This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.</td><td>2</td></tr>
<tr><td>10. Independent system operator/regional transmission organization</td><td colspan="3">This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.</td><td>2</td></tr>
<tr><td rowspan="10">11. Regional reliability organization</td><td colspan="3">This sector includes any regional reliability organization as defined in Article I, Section 1, of the Bylaws of the corporation. In aggregate, this sector will have voting strength equivalent to two members. The voting weight of each regional member's vote will be set such that the sum of the weight of all available regional reliability organizations members' votes is two votes.</td><td rowspan="10">2</td></tr>
<tr><td><u>RRO</u></td><td><u>Number of Members</u></td><td><u>Proportional Voting</u></td></tr>
<tr><td>FRCC</td><td>1</td><td>X</td></tr>
<tr><td>RFC</td><td>1</td><td>X</td></tr>
<tr><td>ERCOT</td><td>1</td><td>X</td></tr>
<tr><td>MRO</td><td>1</td><td>X</td></tr>
<tr><td>NPCC</td><td>1</td><td>X</td></tr>
<tr><td>SERC</td><td>1</td><td>X</td></tr>
<tr><td>SPP</td><td>1</td><td>X</td></tr>
<tr><td>WECC</td><td>1</td><td>X</td></tr>
<tr><td>12. State government</td><td colspan="3">(See Government representatives below)</td><td>2</td></tr>
<tr><td>Officers</td><td colspan="3">Chairman and Vice Chairman</td><td>2</td></tr>
<tr><td colspan="4" align="right">Total Voting Members</td><td>26</td></tr>
</table>

Name	Definition	Members
Non-Voting Members[1]		
Government representatives	This sector includes any federal, state, or provincial government department or agency in North America having a regulatory and/or policy interest in wholesale electricity. Entities with regulatory oversight over the Corporation or any regional entity, including U.S., Canadian, and Mexican federal agencies and any provincial entity in Canada having statutory oversight over the Corporation or a regional entity with respect to the approval and/or enforcement of reliability standards, may be nonvoting members of this sector.	
	United States federal government	2
	Canadian federal government	1
	Provincial government	1
Secretary	The committee secretary will be seated at the committee table	1
Subcommittee Chairmen	The chairmen of the subcommittees will be seated at the committee table.	

[1] Industry associations and organizations and other government agencies in the U.S. and Canada may attend meetings as non-voting observers.

Appendix 2 – Meeting Procedures

Section 1. Voting Procedures for Motions

1. The default procedure is a voice vote.

2. If the chairman believes the voice vote is not conclusive, he may call for a show of hands.

3. The chairman will not specifically ask those who are abstaining to identify themselves when voting by voice or a show of hands.

4. The committee may conduct a roll-call vote in those situations that need a record of each member's vote.

    - The committee must approve conducting a roll call vote for the motion.
    - The secretary will call each member's name.
    - Members answer "yes," "no," or "present" if they wish to abstain from voting.

Section 2. Minutes

1. Meeting minutes are a record of what the committee did, not what its members said.

2. Minutes should list discussion points where appropriate, but should usually not attribute comments to individuals. It is acceptable to cite the chairman's directions, summaries, and assignments.

3. Do not list the person who seconds a motion.

4. Do not record (or even ask for) abstentions.

Section 3. Minority Opinions

All Committees members are afforded the opportunity to provide alternative views on an issue. The meeting minutes will provide an exhibit to record minority opinions. The chairman shall report both the majority and any minority views in presenting results to the Board of Trustees.

Section 4. Personal Statements

The minutes will also provide an exhibit to record personal statements.

Appendix 3 – Reliability Guidelines Approval Process

1. Reliability Guidelines
   Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.[2]

2. Approval of Reliability Guidelines
   Because reliability guidelines contain suggestions that may result in actions by responsible entities, those suggestions must be thoroughly vetted before a new or updated guideline receives approval by a technical committee. The process described below will be followed by the Operating Committee:

   a. New/updated draft guideline approved. The Operating Committee approves release of a new or updated draft guideline developed by one of its subgroups or the committee as a whole.

   b. Post draft guideline for industry comment. The draft guideline is posted for industry-wide comment for forty-five (45) days. If the draft guideline is an update, a redline version against the previous version must also be posted.

   c. Post industry comments and responses. After the public comment period, the Operating Committee posts the comments received as well as its responses to the comments. The committee may delegate the preparation of responses to a committee subgroup.

   d. New/updated guideline approval and posting. A new or updated guideline which considers the comments received, is approved by the sponsoring technical committee and posted on the NERC Web site. Updates must include a revision history and a redline version against the previous version.

   e. Guideline updates. After posting a new or updated guideline, the Operating Committee will continue to accept comments from the industry via a Web-based forum where commenters may post their comments.

      i. Each quarter, the Operating Committee will review the comments received. At any time, the Operating Committee may decide to update the guideline based on the comments received or on changes in the industry that necessitate an update.

      ii. Updating an existing guideline will require that a draft updated guideline be approved by the Operating Committee in step "a" and proceed to steps "b" and "c" until it is approved by the Operating Committee in step "d."

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[2] Standards Committee authorization is required for a reliability guideline to become a supporting document that is posted with or referenced from a NERC Reliability Standard. See Appendix 3A in the NERC's *Rules of Procedure* under "Supporting Documents."

Attachment 2

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Planning Committee Charter

October 29, 2008

to ensure the reliability of the bulk power system

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Table of Contents

Section 1. Purpose

The Planning Committee proactively supports the NERC mission and the several NERC program areas by carrying out a broad array of functions and responsibilities focused on the reliable planning and assessment of interconnected bulk power systems.

Section 2. Functions

1. **General forum.** Provides a general forum for aggregating ideas and interests regarding the reliable planning and assessment of the interconnected bulk power systems in North America.

2. **Advice and recommendations.** Provides NERC (stakeholders, Board of Trustees, and staff) with advice, recommendations, and the collective and diverse opinions on matters related to bulk power system planning, reliability, and adequacy to help the industry arrive at informed decisions. Issue reliability guidelines in accordance with the process described in Appendix 4.

3. **Support to the Reliability Assessment and Performance Analysis Program.** Provides technical support, guidance, and advice to NERC's Reliability Assessment and Performance Analysis Program, which includes:

    a. **Reliability Assessments**

    - Provide input on seasonal, long-term, and special reliability assessment reports, including reliability issues and trends to be addressed in these reports.
    - Review and comment on draft reliability assessment reports.
    - Endorse the approval by the NERC board of reliability assessment reports.

    b. **Events Analysis and Information Exchange**

    - Review and discuss the results of individual event investigations and lessons learned as well as long-term trends.
    - Recommend actions to other NERC programs (standards, compliance, readiness, training, etc.) based on lessons learned and trends from event investigations.
    - Support information exchange within the industry on lessons learned from event investigations, including the issuance of event notifications, significant event reports, and trends in events analysis.

    c. **Reliability Metrics and Benchmarking**

    - Provide input to the Reliability Metrics and Benchmarking Program.
    - Support the development and improvement of NERC's key reliability metrics.

4. **Support to other NERC programs.** Provides technical advice and subject matter expert support to each of the other NERC programs, and serve as a forum to integrate the outputs of these programs, specifically:

a. **Standards**.

- Provide the committee's majority and minority opinions to the industry on NERC's standards as those standards are drafted, posted for ballot, and presented to the board for implementation.
- Help the Standards Committee prioritize those standards that are in the drafting queue.
- Provide technical opinions and interpretations of standards at the request of industry stakeholders or the NERC board.

b. **Compliance**. Review quarterly and annual compliance reports for trends and suggest new or different types of compliance monitoring based on a technical review of system performance trends or as a result of investigations.

c. **Readiness evaluations.** Provide technical advice on readiness evaluation objectives, guidelines, examples of excellence, and review evaluation findings for trends.

5. **Documents and procedures.** Develop and maintain documents and procedures related to the reliable planning and assessment of interconnected bulk power systems, including but not limited to:

a. **Functional model**. Approve the technical content of the NERC Reliability Functional Model.

b. **Reference documents.** Technical reference documents and guidelines on matters including: system modeling and model validation, system static and dynamic analysis, system protection and control, load forecasting, resource adequacy assessment, and reliability data requirements.

c. **Field test procedures**. Field test procedures for prospective reliability standards.

6. **Opinions and guidance.** Provide technical opinions and guidance on planning reliability concepts and philosophies.

Section 3. Membership

1. **Goals.** The Planning Committees provides for balanced decision making by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in the area of interconnected systems planning reliability and reliability assessment.

2. **Expectations.** Planning Committee voting members are expected to:

a. Bring subject matter expertise to the Planning Committee

b. Be knowledgeable about planning reliability and reliability assessment

c. Attend and participate in all Planning Committee meetings

d. Express their opinions as well as the opinions of the sector they represent at committee meetings.

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b. To ensure adequate Canadian representation, the membership to the committee may be increased so that the number of Canadian voting members is equal to the percentage of the net energy for load (NEL) of Canada to the total NEL of the United States and Canada, times the total number of voting members on the committee, rounded to the next whole number.

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   a. Members who resign will be replaced for the time remaining in the member's term. Members will be replaced pursuant to Section 4, officers will be replaced pursuant to Appendix 3, and executive committee members will be replaced pursuant to Section 7.

   b. The secretary will submit the new member's name to the board for approval at the board's next regular meeting.

   c. The committee may approve the new member on an interim basis at the committee's next meeting.

   d. The committee chair will contact any member who has missed two consecutive meetings (even if the member has sent a proxy) to 1) seek a commitment to actively participate or 2) ask the member to resign from the committee.

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   a. Meets the member's eligibility requirements (see Section 3.3a) and is not affiliated with the same organization as another committee member (see Section 3.4c), or

   b. Is not another committee member, unless that committee member would represent the proxy's sector instead of his/her own sector at the meeting.

   To permit time to determine a proxy's eligibility, proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable). Any proxy submitted after that time will be accepted at the chairman's discretion, provided that the chairman believes the proxy meets the eligibility requirements.

Section 4. Meetings.

See Appendix 2, "Meeting Procedures." Unless stated otherwise, the Planning Committee will follow Robert's Rules of Order, Newly Revised.

1. **Quorum.** The quorum necessary for the transaction of business (i.e., formal actions) at meetings of the committee is two-thirds of the voting members currently on the committee roster (i.e., does not count vacancies). The committee may engage in discussions without a quorum present.

2. **Voting.** Actions by members of the committee shall be approved upon receipt of the affirmative vote of two-thirds of the voting members of the committee present and voting, in person or by proxy, at any meeting at which a quorum is present. The chair and vice chair may vote. Additional voting guidelines are in Appendix 2.

3. **Antitrust Guidelines.** All persons attending or otherwise participating in the committee meeting shall act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting. A copy of the NERC antitrust statement shall be included with each meeting agenda.

4. **Open Meetings.** NERC committee meetings shall be open to the public, except as noted below under Confidential Sessions. Although meetings are open, only voting members may offer and act on motions.

5. **Confidential Sessions.** The chair of a committee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a nondiscriminatory basis as needed to protect information that is sensitive to one or more parties. A preference, where possible, is to avoid the disclosure of sensitive or confidential information so that meetings may remain open at all times. Confidentiality agreements may also be applied as necessary to protect sensitive information.

Section 5. Officers.

See Appendix 3, "Officer Selection Process"

1. **Selection.** At its first June meeting and every two years thereafter, the committee shall select a chair and vice chair from among its voting members by majority vote of the members of the committee to serve as chair and vice chair of the committee from the end of that June meeting until the end of the June meeting two years later.

2. **Terms.** The chair and vice chair serve two-year terms.

3. **Representation.**

    a. The newly selected chair and vice chair shall not be from of the same sector.

    b. The chair and vice chair, upon assuming such positions, shall cease to act as members of the sectors that elected them as members to the committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

4. **Board approval.** The secretary will submit the elected officers to the chair of the board for approval.

Section 6. Subcommittees

The Planning Committee may appoint technical subcommittees, task forces, and working groups as needed. The Planning Committee is responsible for directing the work of these subgroups and for their work products.

Section 7. Executive Committee

1. **Authorization.** The executive committee is authorized to act between regular meetings of the Planning Committee. However, the executive committee may not reverse the Planning Committee's decisions.

2. **Membership.** The executive committee is comprised of the chair, the vice chair, and four at-large members. The committee will nominate and elect the four at-large members of the executive committee at its September meeting. No two members may be from the same sector.

3. **Election Process.**

   a. The chair opens the floor for nominations.

   b. If the committee members nominated four or fewer candidates, then those candidates are automatically elected.

   c. If the committee members nominate more than four candidates, then the secretary will distribute paper ballots for the members to list their top four candidates.

   d. The four candidates who receive the most votes will be elected, provided that no two candidates may be from the same sector.

4. **Terms.** The executive committee will be replaced every two years, with the chair and vice chair replaced at a June meeting and the at-large members replaced at a September meeting.

Appendix 1 – Committee Members

Name	Definition	Members
Voting Members		
1. Investor-owned utility	This sector includes any investor-owned entity with substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission, or distribution. This sector also includes organizations that represent the interests of such entities.	2
2. State/municipal utility	This sector includes any entity owned by or subject to the governmental authority of a state or municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state or municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating, transmitting, or purchasing electricity for sale at wholesale to their members. This sector also includes organizations that represent the interests of such entities.	2
3. Cooperative utility	This sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities. This sector also includes organizations that represent the interests of such entities.	2
4. Federal or provincial utility/Federal Power Marketing Administration	This sector includes any U.S. federal, Canadian provincial, or Mexican entity that owns and/or operates electric facilities in any of the asset categories of generation, transmission, or distribution; or that functions as a power marketer or power marketing administrator. This sector also includes organizations that represent the interests of such entities. One member will be a U.S. federal entity and one will be a Canadian provincial entity.	2
5. Transmission dependent utility	This sector includes any entity with a regulatory, contractual, or other legal obligation to serve wholesale aggregators or customers or end-use customers and that depends primarily on the transmission systems of third parties to provide this service. This sector also includes organizations that represent the interests of such entities.	2
6. Merchant electricity generator	This sector includes any entity that owns or operates an electricity generating facility that is not included in an investor-owned utility's rate base and that does not otherwise fall within any of sectors (i) through (v). This sector includes but is not limited to cogenerators, small power producers, and all other non-utility electricity producers such as exempt wholesale generators who sell electricity at wholesale. This sector also includes organizations that represent the interests of such entities.	2
7. Electricity marketer	This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.	2

Name	Definition			Members
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8. Large end-use electricity customer	This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.			2
9. Small end-use electricity customer	This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.			2
10. Independent system operator/regional transmission organization	This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.			2
11. Regional reliability organization	This sector includes any regional reliability organization as defined in Article I, Section 1, of the Bylaws of the corporation. In aggregate, this sector will have voting strength equivalent to two members. The voting weight of each regional member's vote will be set such that the sum of the weight of all available regional reliability organizations members' votes is two votes.			2
	RRO	Number of Members	Proportional Voting	
	FRCC	1	X	
	RFC	1	X	
	ERCOT	1	X	
	MRO	1	X	
	NPCC	1	X	
	SERC	1	X	
	SPP	1	X	
	WECC	1	X	
12. State government	(See Government representatives below)			2
Officers	Chair and Vice Chair			2
			Total Voting Members	**26**
Non-Voting Members[1]				

[1] Industry associations and organizations and other government agencies in the U.S. and Canada may attend meetings as non-voting observers.

Name	Definition	Members
Voting Members		
Government representatives	This sector includes any federal, state, or provincial government department or agency in North America having a regulatory and/or policy interest in wholesale electricity. Entities with regulatory oversight over the Corporation or any regional entity, including U.S., Canadian, and Mexican federal agencies and any provincial entity in Canada having statutory oversight over the Corporation or a regional entity with respect to the approval and/or enforcement of reliability standards, may be nonvoting members of this sector.	
	United States federal government	2
	Canadian federal government	1
	Provincial government	1
Regional reliability organizations	The remaining RROs that are not RRO sector voting members.	6
Secretary	The committee secretary will be seated at the committee table	1
Subcommittee Chairs	The chairs of the subcommittees will be seated at the committee table.	

Appendix 2 – Meeting Procedures

Section 1. Voting Procedures for Motions

a. The default procedure is a voice vote.

b. If the chair believes the voice vote is not conclusive, he may call for a show of hands.

c. The chair will not specifically ask those who are abstaining to identify themselves when voting by voice or a show of hands.

d. The committee may conduct a roll-call vote in those situations that need a record of each member's vote.

- The committee must approve conducting a roll-call vote for the motion.
- The secretary will call each member's name.
- Members may answer "yes," "no," or "present" if they wish to abstain from voting.

Section 2. Minutes

1. **General guidelines.**

a. Meeting minutes are a record of what the committee did, not what its members said.

b. Minutes should list discussion points where appropriate, but should usually not attribute comments to individuals. It is acceptable to cite the chair's directions, summaries, and assignments.

c. Do not list the person who seconds a motion.

d. Do not record (or even ask for) abstentions.

2. **Minority Opinions.** All committee members are afforded the opportunity to provide alternative views on an issue. The meeting minutes will provide an exhibit to record minority opinions. The chair shall report both the majority and any minority views in presenting results to the Board of Trustees.

3. **Personal Statements.** The minutes will also provide an exhibit to record personal statements.

Appendix 3 – Officer Selection Process

The committee selects officers using the following process. The chair is selected first, followed by the vice chair.

a. The chair opens the floor for nominations.

b. After hearing no further nominations, the chair closes the nominating process.

c. If the committee nominates one person, that person is automatically selected as the next chair.

d. If the committee nominates two or more persons, then the secretary will distribute paper ballots for the members to mark their preference.

e. The secretary will collect the ballots. If the committee nominates three or more candidates, then the winner will be selected using the Instant Runoff Process. (Explained in Robert's Rules of Order.)

Appendix 4 – Reliability Guidelines Approval Process

1. Reliability Guidelines
   Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.[2]

2. Approval of Reliability Guidelines
   Because reliability guidelines contain suggestions that may result in actions by responsible entities, those suggestions must be thoroughly vetted before a new or updated guideline receives approval by a technical committee. The process described below will be followed by the Planning Committee:

   a. New/updated draft guideline approved. The Planning Committee approves release of a new or updated draft guideline developed by one of its subgroups or the committee as a whole.

   b. Post draft guideline for industry comment. The draft guideline is posted for industry-wide comment for forty-five (45) days. If the draft guideline is an update, a redline version against the previous version must also be posted.

   c. Post industry comments and responses. After the public comment period, the Planning Committee posts the comments received as well as its responses to the comments. The committee may delegate the preparation of responses to a committee subgroup.

   d. New/updated guideline approval and posting. A new or updated guideline which considers the comments received, is approved by the sponsoring technical committee and posted on the NERC Web site. Updates must include a revision history and a redline version against the previous version.

   e. Guideline updates. After posting a new or updated guideline, the Planning Committee will continue to accept comments from the industry via a Web-based forum where commenters may post their comments.

      i. Each quarter, the Planning Committee will review the comments received. At any time, the Planning Committee may decide to update the guideline based on the comments received or on changes in the industry that necessitate an update.

      ii. Updating an existing guideline will require that a draft updated guideline be approved by the Planning Committee in step "a" and proceed to steps "b" and "c" until it is approved by the Planning Committee in step "d."

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[2] Standards Committee authorization is required for a reliability guideline to become a supporting document that is posted with or referenced from a NERC Reliability Standard. See Appendix 3A in the NERC's *Rules of Procedure* under "Supporting Documents."

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Planning Committee Charter

~~July 30~~October 29, 2008

to ensure the reliability of the bulk power system

116-390 Village Blvd., Princeton, NJ 08540
609.452.8060 | 609.452.9550 fax
www.nerc.com

Table of Contents

Section 1. Purpose

The Planning Committee proactively supports the NERC mission and the several NERC program areas by carrying out a broad array of functions and responsibilities focused on the reliable planning and assessment of interconnected bulk power systems.

Section 2. Functions

1. **General forum.** Provides a general forum for aggregating ideas and interests regarding the reliable planning and assessment of the interconnected bulk power systems in North America.

2. **Advice and recommendations.** Provides NERC (stakeholders, Board of Trustees, and staff) with advice, recommendations, and the collective and diverse opinions on matters related to bulk power system planning, reliability, and adequacy to help the industry arrive at informed decisions. Issue reliability guidelines in accordance with the process described in Appendix 4.

3. **Support to the Reliability Assessment and Performance Analysis Program.** Provides technical support, guidance, and advice to NERC's Reliability Assessment and Performance Analysis Program, which includes:

   a. **Reliability Assessments**

   - Provide input on seasonal, long-term, and special reliability assessment reports, including reliability issues and trends to be addressed in these reports.
   - Review and comment on draft reliability assessment reports.
   - Endorse the approval by the NERC board of reliability assessment reports.

   b. **Events Analysis and Information Exchange**

   - Review and discuss the results of individual event investigations and lessons learned as well as long-term trends.
   - Recommend actions to other NERC programs (standards, compliance, readiness, training, etc.) based on lessons learned and trends from event investigations.
   - Support information exchange within the industry on lessons learned from event investigations, including the issuance of event notifications, significant event reports, and trends in events analysis.

   c. **Reliability Metrics and Benchmarking**

   - Provide input to the Reliability Metrics and Benchmarking Program.
   - Support the development and improvement of NERC's key reliability metrics.

4. **Support to other NERC programs.** Provides technical advice and subject matter expert support to each of the other NERC programs, and serve as a forum to integrate the outputs of these programs, specifically:

a. **Standards**.

- Provide the committee's majority and minority opinions to the industry on NERC's standards as those standards are drafted, posted for ballot, and presented to the board for implementation.
- Help the Standards Committee prioritize those standards that are in the drafting queue.
- Provide technical opinions and interpretations of standards at the request of industry stakeholders or the NERC board.

b. **Compliance**. Review quarterly and annual compliance reports for trends and suggest new or different types of compliance monitoring based on a technical review of system performance trends or as a result of investigations.

c. **Readiness evaluations.** Provide technical advice on readiness evaluation objectives, guidelines, examples of excellence, and review evaluation findings for trends.

5. **Documents and procedures.** Develop and maintain documents and procedures related to the reliable planning and assessment of interconnected bulk power systems, including but not limited to:

a. **Functional model**. Approve the technical content of the NERC Reliability Functional Model.

b. **Reference documents.** Technical reference documents and guidelines on matters including: system modeling and model validation, system static and dynamic analysis, system protection and control, load forecasting, resource adequacy assessment, and reliability data requirements.

c. **Field test procedures**. Field test procedures for prospective reliability standards.

6. **Opinions and guidance.** Provide technical opinions and guidance on planning reliability concepts and philosophies.

Section 3. Membership

1. **Goals.** The Planning Committees provides for balanced decision making by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in the area of interconnected systems planning reliability and reliability assessment.

2. **Expectations.** Planning Committee voting members are expected to:

a. Bring subject matter expertise to the Planning Committee

b. Be knowledgeable about planning reliability and reliability assessment

c. Attend and participate in all Planning Committee meetings

d. Express their opinions as well as the opinions of the sector they represent at committee meetings.

e. Discuss and debate interests rather than positions

f. Complete committee assignments

g. Inform the secretary of any changes in their status that may affect their eligibility for committee membership. Failure to do so in a timely manner may result in the member's dismissal by the chair.

3. **Representation.** See Appendix 1, "Committee Members."

a. Committee members may, but need not be, NERC members. A non-voting representative must meet the requirements defined in Appendix 1. Voting committee members (except for sector 11 that appoints it members) may hold a position in any sector in which they would have been eligible for NERC membership, even if they are a NERC member in another sector. Questions regarding eligibility for committee membership will be referred to the NERC general counsel for final determination of status.

b. To ensure adequate Canadian representation, the membership to the committee may be increased so that the number of Canadian voting members is equal to the percentage of the net energy for load (NEL) of Canada to the total NEL of the United States and Canada, times the total number of voting members on the committee, rounded to the next whole number.

4. **Selection.** Except for sector 11, NERC sector members will annually elect voting committee members ~~in~~ to committee sectors corresponding to their NERC sector under an election process that is open, inclusive, and fair. The selection process will be completed in time for the secretary to send the committee membership list to the board for its approval at the board's August meeting so that new committee members may be seated at the September meeting.

a. Un-nominated voting member positions will remain vacant until the next annual election, or until the committee secretary receives a nomination for that position, whichever occurs first.

b. Members may not represent more than one committee sector.

c. A particular organization, including its affiliates, may not have more than one member on the committee.

d. If additional Canadian members are added, no more than one additional Canadian voting member shall be selected from a sector unless this limitation precludes the addition of the number of additional Canadian voting representatives required by Section 3.3.b. In this case, no more than two additional Canadian voting members may be selected from the same sector.

e. The secretary will monitor the committee selection process to insure that membership specifications are met.

5. **Terms.** Members' terms are staggered, with one-half of the members' terms expiring each year. Except for the ~~initial selection~~cases described below, a member's term is two years and will commence on the first September meeting following the member's selection

pursuant to Section 3.4 and continue until the September meeting two years later. Members may be re-elected for subsequent terms. Shorter terms may be required for several reasons: (i) If two members are simultaneously selected to a sector that did not have any existing members, in order to stagger their terms, one member will be assigned a one-year term and the second member will be assigned a two-year term using a fair and unbiased method. (ii) If a member replaces a departed member between elections, the new member will assume the remaining term of the departed member. (iii) If a member is selected to fill a vacant member position between elections, his/her term will end when the term for that vacant position ends.

6. **Resignations, Vacancies, and Nonparticipation.**

   a. Members who resign will be replaced for the time remaining in the member's term. Members will be replaced pursuant to Section 4, officers will be replaced pursuant to Appendix 3, and executive committee members will be replaced pursuant to Section 7.

   b. The secretary will submit the new member's name to the board for approval at the board's next regular meeting.

   c. The committee may approve the new member on an interim basis at the committee's next meeting.

   d. The committee chair will contact any member who has missed two consecutive meetings (even if the member has sent a proxy) to 1) seek a commitment to actively participate or 2) ask the member to resign from the committee.

   e. The chair may remove any member who has missed two consecutive meetings (even with a proxy).

7. **Proxies.** A member of the committee may give a proxy only to a person who:

   a. Meets the member's eligibility requirements (see Section 3.3a) and is not affiliated with the same organization as another committee member~~. This provision is consistent with~~ (see Section 3.4~~.~~c~~. Each voting member of the committee shall have one vote on any matter coming before the committee that requires a vote.~~), or

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   To permit time to determine a proxy's eligibility, proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable). Any proxy submitted after that time will be accepted at the chairman's discretion, provided that the chairman believes the proxy meets the eligibility requirements.

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The committee selects officers using the following process. The chair is selected first, followed by the vice chair.

a. The chair opens the floor for nominations.

b. After hearing no further nominations, the chair closes the nominating process.

c. If the committee nominates one person, that person is automatically selected as the next chair.

d. If the committee nominates two or more persons, then the secretary will distribute paper ballots for the members to mark their preference.

e. The secretary will collect the ballots. If the committee nominates three or more candidates, then the winner will be selected using the Instant Runoff Process. (Explained in Robert's Rules of Order.)

Appendix 4 – Reliability Guidelines Approval Process

1. Reliability Guidelines
   Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.[2]

2. Approval of Reliability Guidelines
   Because reliability guidelines contain suggestions that may result in actions by responsible entities, those suggestions must be thoroughly vetted before a new or updated guideline receives approval by a technical committee. The process described below will be followed by the Planning Committee:

   a. New/updated draft guideline approved. The Planning Committee approves release of a new or updated draft guideline developed by one of its subgroups or the committee as a whole.

   b. Post draft guideline for industry comment. The draft guideline is posted for industry-wide comment for forty-five (45) days. If the draft guideline is an update, a redline version against the previous version must also be posted.

   c. Post industry comments and responses. After the public comment period, the Planning Committee posts the comments received as well as its responses to the comments. The committee may delegate the preparation of responses to a committee subgroup.

   d. New/updated guideline approval and posting. A new or updated guideline which considers the comments received, is approved by the sponsoring technical committee and posted on the NERC Web site. Updates must include a revision history and a redline version against the previous version.

   e. Guideline updates. After posting a new or updated guideline, the Planning Committee will continue to accept comments from the industry via a Web-based forum where commenters may post their comments.

      i. Each quarter, the Planning Committee will review the comments received. At any time, the Planning Committee may decide to update the guideline based on the comments received or on changes in the industry that necessitate an update.

      ii. Updating an existing guideline will require that a draft updated guideline be approved by the Planning Committee in step "a" and proceed to steps "b" and "c" until it is approved by the Planning Committee in step "d."

[2] Standards Committee authorization is required for a reliability guideline to become a supporting document that is posted with or referenced from a NERC Reliability Standard. See Appendix 3A in the NERC's *Rules of Procedure* under "Supporting Documents."

Agenda Item 3
Board of Trustees Meeting
October 29, 2008

Future Meetings

Board Action Required

Approve November 4–5, 2009 (W–Th) in Atlanta, Georgia as a future meeting date and location

Information

The board has approved the following future meeting dates and locations:

- February 9–10, 2009 — Phoenix, Arizona (M–Tu)
- May 5–6, 2009 — Washington, D.C. (Tu–W)
- August 4–5, 2009 — Winnipeg, Manitoba, Canada (Tu–W)

Reliability Standards

Board Action Required

Approve reliability standards in the following areas:

a. Reliability Standards Development Plan: 2009–2011 — **Approve**
b. Standards Errata and Errata Procedure — **Approve**
c. Project 2007-14 — Permanent Changes to Coordinate Interchange Timing Tables — **Approve**
d. Status of Standards Development — **Information Only**
e. Consideration of WECC Tier 1 Reliability Standards — **Approve**

Information

The Reliability Standards Program is responsible for all aspects of NERC's Reliability Standards, including: developing and maintaining reliability standards; the reliability standards development process; and the review of proposed regional standards. This program also has primary responsibility for managing NERC's relationship with the North American Energy Standards Board, which develops business practice standards and communications protocols for electric and gas wholesale and retail market participants. The standards program depends on the active involvement of industry subject matter experts to both recommend and develop reliability standards.

a. Reliability Standards Development Plan: 2009–2011 — Approve

Background:
The *Reliability Standards Development Plan: 2009–2011* is the third installment of the development plan and was approved by the Standards Committee on September 24, 2008. The development plan serves as a management tool to guide and coordinate the development of reliability standards and provide benchmarks for assessing progress. The plan also serves as a communications tool for coordinating standards development work with applicable governmental agencies in the United States and Canada, and for engaging stakeholders in standards development. The plan further provides a basis for developing annual work plans and budgets for the standards program. The initial and second versions of the development plan were accepted by the board in November 2006 and September 2007, respectively, and subsequently filed as informational filings with the applicable governmental agencies in the United States and Canada.

The 2009–2011 development plan comprises three volumes:

- **Volume I** provides an overview of the plan, including the history of the current status of standards activities related to the development and approval of standards;
- **Volume II** details the specific standards development projects; and,
- **Volume III** summarizes the reliability standards activity anticipated over the three-year period covered by the plan.

The development plan demonstrates NERC's comprehensive and proactive program to improve the existing reliability standards as well as a commitment to the timely development of new high-priority reliability standards. The plan also addresses the "fill-in-the-blank" Regional standards that were neither approved nor remanded by FERC in Order No. 693, and individual projects whose scopes include the regulatory directives from Commission's Orders that have been issued up to and including Order No. 693 to the present.

Accounts for the Views of NERC's Stakeholders
To support the preparation of this revised development plan, NERC sought stakeholder input through a variety of forums from April–August 2008. These comments and NERC's response to these comments are included in Appendix A to Volume I of the revised plan. The comments are summarized as follows:

- Several commenters indicated there are limited industry resources to focus on standards development activities and the scope of the plan should focus efforts on the projects most crucial to reliability. In response, projects were realigned in the years included in the development plan to acknowledge the constraints on the amount of industry resources available to develop quality standards.
- Divergent comments were received related to adherence to project schedules. Some commenters suggested projects should be developed while remaining dynamic and subject to potential changes. Others insisted that strict schedules should be developed and adhered to. NERC commits to developing project schedules that provide better projections for completion dates.
- A few specific suggestions were received that certain projects should be addressed sooner in the plan, rather than later. The targeted projects were either already underway (Vegetation Management or Cyber Security) or scheduled to commence early in 2009 (Disturbance and Sabotage Reporting).

In addition, NERC staff requested input from its technical committees to identify any expected standards requests in the timeframe contemplated by the development plan. The final report of the *Real-Time Tools Best Practices Task Force* was issued in early 2008 and Project 2009-02 — Real-time Tools was added to the revised plan to address the recommendations contained in the report.

NERC staff also coordinated with the North American Energy Standards Board (NAESB), Wholesale Electric Quadrant (WEQ), and the Standards Review Subcommittee (SRS) to identify those projects that may require complementary NAESB business practices. The following projects may require coordinated NAESB business practices:

- Project 2006-07 — Transfer Capabilities — (ATC, TTC, CBM, TRM)
- Project 2006-08 — Transmission Loading Relief
- Project 2007-05 — Balancing Authority Controls
- Project 2007-18 — Reliability-based Control
- Project 2008-01 — Voltage and Reactive Control
- Project 2008-03 — Emergency Operations (moved to Project 2009-03 in this plan)
- Project 2009-02 — Connecting New Facilities to the Grid (moved to Project 2010-02 in this plan)
- Project 2009-03 — Interchange Information (moved to Project 2008-12 in this plan)

In response, NERC added a new section entitled "Coordination with NAESB" to the project description of each affected project in Volume II of the revised plan. This new section includes information related to the coordination with NAESB for the drafting team to consider in the development of the associated reliability standard(s).

Significant Revisions in *Reliability Standards Development Plan: 2009–2011*

The total number of projects proposed in the 2009–2011 development plan increased to 39, up three from the 36 listed in the 2008–2010 version of the plan. The changes in the proposed 2009–2011 development plan include:

- Four new standards development projects that were not included in previous versions of the plan:
  - Two new projects for 2008 that were not anticipated in the 2008–2010 plan;
    - Project 2008-05 — Credible Multiple Element Contingencies
    - Project 2008-08 — EOP Violation Severity Levels Revisions
  - One new project in 2009:
    - Project 2009-02 — Real-time Tools
  - One new project in 2011:
    - Project 2011-01 — Equipment Monitoring and Diagnostic Devices
- Removal of one project identified in the 2008–2010 plan that has been completed:
  - Operate Within Interconnection Reliability Operating Limits
- Advancement of two projects that were slated to begin in 2009 per the current plan that were actually initiated in 2008 (earlier than anticipated):
  - Project 2008-12 — Coordinate Interchange Standards replaces Project 2009-03 — Interchange Information from the 2008–2010 plan
  - Project 2008-06 — Cyber Security Order 706 replaces Project 2009-07 — Cyber Security from the 2008–2010 plan
- Reassignment of one project from 2008 to 2009 and four projects from 2009 to 2010 to recognize the limits to available industry resources for review of the many development activities contemplated by the development plan:
  - Project 2008-03 — Emergency Operations was moved to 2009 and relabeled as Project 2009-03 — Emergency Operations
  - Project 2009-02 — Connecting New Facilities to the Grid was moved to 2010 and relabeled as Project 2010-02 — Connecting New Facilities to the Grid
  - Project 2009-04 — Modeling Data was moved to 2010 and relabeled as Project 2010-03 — Modeling Data
  - Project 2009-05 — Demand Data was moved to 2010 and relabeled as Project 2010-04 — Demand Data
  - Project 2009-06 — Protection Systems was moved to 2010 and relabeled as Project 2010-05 — Protection Systems
- Modifications to individual projects to:

- Clearly identify the need for coordination with the North American Energy Standards Board (NAESB); and,
- Comply with FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 regarding Load Serving Entities.

FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Regarding Load Serving Entities

On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which FERC reversed a NERC decision to register three retail power marketers to comply with reliability standards applicable to load serving entities (LSEs). FERC also directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following long-term plan to address the potential gap:

- "NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year *Reliability Standards Development Plan*."

This revised *Reliability Standards Development Plan: 2009–2011*, includes following description in the scope for affected projects that includes a standard applicable to Load Serving Entities:

> **Source:** FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000
>
> **Issue:** In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the Reliability*First* (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate reliability standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see:
>
> - FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf)
> - NERC's March 4, 2008 Compliance Filing (http://www.nerc.com/files/FinalFiledLSE3408.pdf),
> - FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and
> - NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.

b. Standards Errata and Errata Procedure — Approve

Action: Approve filings of standards errata with FERC and Canadian regulatory authorities.

Background: At its September 2008 meeting, the NERC Standards Committee approved a procedure to provide an approval process for incorporating errata changes in approved reliability standards. Errata can include such things as:

- A misspelled word,
- An incorrect reference to a requirement or measure,
- An error, such as a missing word etc. that, when added or corrected, does not change the scope or technical content of the standard.

The procedure approved by the Standards Committee is as follows:

Responsibility	Activity
Standards Administrator	Forward each notice of an error in an approved standard to the Standards Process Manager.
Standards Process Manager	If the error falls into the errata category, produce a clean and red line version of the standard that shows the proposed correction(s). If the error is associated with an active project notify the drafting team of the error so that the error is not duplicated. If the error does not meet the errata criteria, and there are no active standards projects involving the applicable standard, add the error to the "Standards Issues Database" for inclusion in the next SAR submitted to revise the associated standard.
Standards Committee	Review the proposed errata modification and determine if it qualifies as errata as defined above. The Standards Committee may seek the opinion of a technical committee. If approved as errata, direct staff to post the clean and red line versions of the standard for a 30-day comment period.
Standards Process Manager	If the Standards Committee authorizes posting for stakeholder comment: • Post the clean and red line versions of the standard for a 30-day comment period. • Identify the posting as an errata change and ask stakeholders if they agree that the proposed modification is immaterial and if they support the modification. • Provide a timetable including when the board will act on the errata.
Stakeholders	Provide comments on proposed errata. If stakeholders do not support the revision as errata they should include reasons why they believe the change is material or does not qualify as errata.
Standards Committee's Process Subcommittee	Prepare responses to stakeholder comments and submit with a recommendation to the Standards Committee for review and action.
Standards Committee	Review Process Subcommittee recommendation and determine whether to make further modifications to the draft standard and post again, seek the opinion of a technical committee, or authorize moving the errata forward for board adoption and filing with regulatory authorities.
Director, Standards	Submit the revised standard and errata to the board for its approval.
Board of Trustees	The board shall adopt or reject the revised standard as errata, but may not modify the proposed reliability standard. If the board chooses not to adopt the

Responsibility	Activity
	revised standard, it shall provide its reasons for not doing so.
Standards Administrator	Modify the board approved version of the standard to include the approved correction, update the standard's version number and send a notice of the approval and associated modification to the standards list servers.
Director, Standards	Submit the revised standard and errata to applicable regulatory authorities for approval.
Standards Administrator	Once approval is received from applicable regulatory authorities, modify applicable regulatory approved version and send a notice to the standards list servers.

Because the errata changes alter the text of a regulatory approved reliability standard, the reliability standard must be filed with FERC and the regulatory authorities in Canada for approval. In the interest of timeliness and effectiveness, NERC staff proposes that the board grant blanket approval for staff to file reliability standards that contain errata changes processed and approved using the approved procedure of the Standards Committee.

The Standards Committee implemented its errata approval procedure to process the following errata changes that had been identified since the last version of each standard was presented for regulatory approval.

Standard Number	Standard Title	Section Number	Description of Correction	Date Revised
BAL-001-0a	Real Power Balancing Control Performance	Sections A, F;	• In Section A.2., Added "a" to end of standard number. The "a" was mistakenly omitted when the BAL-001-0a was filed with FERC. • In Section F, corrected automatic numbering from "2" to "1" and added parenthesis to "(October 23, 2007)."	01/16/08
BAL-003-0a	Frequency Response and Bias	Section F;	• Section F: added "1.";	01/16/08
BAL-005-0a		Sections A, F;	• In Section A.2., Added "a" to end of standard number. The "a" was mistakenly omitted when the BAL-005-0a was filed with FERC. • Section F: added "1.";	01/16/08
BAL-006-1	Inadvertent Interchange	Effective Date	Removed "This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first."	05/09/07
COM-001-1	Telecommunications	R1.	Added the word "for" between "facilities" and "the exchange." Inadvertently omitted.	04/06/07
EOP-002-1 (carried forward to EOP-002-2)	Capacity and Energy Emergencies	R7.	Changed R7. to refer to "Requirement 6" instead of "Requirement 7."	09/19/06
EOP-002-2	Capacity and Energy Emergencies	A.4. Applicability	Corrected numbering in Section A.4. "Applicability."	01/24/07
EOP-002-2	Capacity and Energy Emergencies	A.4. Applicability	Added inadvertently omitted "4.3. Load-Serving Entity" to Applicability Section.	10/01/07
EOP-004-1	Disturbance Reporting	Attachment 2 and Table 1	Updated Department of Energy link and corrected references to Form OE-411.	3/22/07
FAC 010-1, 011-1, 014-1 Implementation Plan	Implementation Plan	Page 2	Reference corrected in TOP-004 discussion: R6.1 and R6.5 are to be retired coincident with implementation of FAC-014, not FAC-011.	06/27/08
IRO-001-1	Reliability Coordination — Responsibilities and Authorities	D.1.3.	Changed "Distribution Provider" to Transmission Service Provider." Distribution Provider was inappropriately listed in the Compliance – Data Retention section.	11/19/06
MOD-006-0	Procedures for Use of CBM Values	Requirement R1	Replaced "preservation" with "reservation" in R1.	09/17/07
MOD-015-0	Development of Dynamic System Models	C. Measure M1.	Corrected typo in Section M1. — removed reference to Requirement R3 as it does not exist.	01/26/07
MOD-016-1	Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management	R2. and R3.	Corrected sequential numbering problem in Sections R2. and R3.	01/26/07
MOD-017-0	Aggregated Actual and Forecast Demands and Net Energy for Load	R1. and D1.2.	Revised R1 and D1.2. to reflect update in version from "MOD-016-0_R1" to MOD-016-1_R1."	05/18/07
MOD-019-0	Forecasts of Interruptible Demands and DCLM Data	R1. and D1.2.	Revised R1 and D1.2. to reflect update in version from "MOD-016-0_R1" to MOD-016-1_R1."	07/24/07

Standard Number	Standard Title	Section Number	Description of Correction	Date Revised
PRC-016-0	Special Protection System Misoperations	C. Measure M1.	Change erroneous reference in Measure 1 from "PRC-016-0_R1" to "PRC-012-0_R1."	07/03/07
TOP-005-1	Operational Reliability Information	Compliance Section D.2.1 and D.2.4	Revised D.2.1 and D.2.4 reference "Requirements R1 to R5" "to Requirements R1 to R4."	10/23/07
TPL-001-0	System Performance Under Normal Conditions	C. Measure M1.	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	07/24/07
VAR-002-1a	Generator Operation for Maintaining Network voltage Schedules	Sections A, F; Appendix 1	• In Section A.2., Added "a" to end of standard number. • Section F: added "1." and date of BOT approval.	01/16/08

At its September 2008 meeting, the Standards Committee approved the following three recommendations with regard to the list of errata identified in the chart.

1. Move the identified corrections to the following standards forward for adoption by the Board of Trustees without any additional modifications:
    - BAL-001-0a — Real Power Balancing Control Performance
    - BAL-003-0a — Frequency Response and Bias
    - BAL-005-0a — Automatic Generation Control
    - BAL-006-1 — Inadvertent Interchange
    - COM-001-1 — Telecommunications
    - FAC-010-1, FAC-011-1, FAC-014-1 — Implementation Plan
    - MOD-015-0 — Development of Interconnection-Specific Dynamic System Models
    - MOD-016-1 — Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy For Load, and Controllable Demand Side Management
    - MOD-017-0 — Aggregated Actual and Forecast Demands and Net Energy For Load
    - MOD-019-0 — Forecasts of Interruptible Demands and DCLM
    - PRC-016-0 — System Protection System Misoperations
    - TOP-005-1 — Operational Reliability Information
    - TPL-001-0 — System Performance Under Normal Conditions
    - VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules

2. Move the already identified corrections to the following standards forward for adoption by the Board of Trustees with the additional modifications noted by stakeholders:
    - EOP-002-2 — Capacity and Energy Emergencies
        - Corrected date in the version history table
    - IRO-001-1 — Reliability Coordination — Responsibilities and Authorities
        - Removed the word, "Proposed" from the "Effective Date" subheading
    - MOD-006-0 — Procedures for Use of CBM Values
        - Corrected the typographical error (preservation to reservation) in the measures to match the correction identified in the requirement

3. Remand the proposed corrections to the following standard for inclusion in Project 2009-01 — Disturbance and Sabotage Reporting:
    - EOP-004-1 — Disturbance Monitoring

Therefore, with the exception of EOP-004-1, staff requests the board approve the noted errata changes identified in the table, with additional modifications to EOP-002-2, IRO-001-1, and MOD-006-0, and file the revised standards that include these errata changes with FERC and applicable regulatory authorities in Canada.

c. **[Project 2007-14 — Permanent Changes to Coordinate Interchange Timing Tables]() — Approve**

Action: Approve permanent changes to the following standards and associated definitions:

- INT-005-3 — Interchange Authority Distributes Arranged Interchange
- INT-006-3 — Response to Interchange Authority
- INT-008-3 — Interchange Authority Distributes Status

Direct staff to file these revised standards with FERC and applicable governmental authorities in Canada.

Background: An Urgent Action SAR was developed in 2007 to make a change to the Coordinate Interchange Timing Table for WECC to increase the reliability assessment time from five minutes to 10 minutes for Requests for Interchange (RFIs) submitted from one hour up to 20 minutes prior to ramp start time. With only five minutes to assess the interchange, WECC reliability entities were unable to assess many RFIs and therefore the arranged interchange was not implemented. This process resulted in Version 2 of these standards that were approved by the board in May 2007. Per the Reliability Standards Development Procedure, the permanent standards that replace those created under the urgent action process must be balloted within one year if no substantive changes are made, or within two years if substantive changes occur, else the urgent action modifications expire. Version 3 of these standards includes substantive changes.

The SAR for this project was submitted in February 2007, posted for industry comment, and ultimately approved by the Standards Committee in August 2007. The revised standards were drafted and posted twice, initially for a 45-day comment period and then for a 30-day comment period that concluded in June 2008. The team responded to comments and requested the approval of the Standards Committee to proceed to the balloting phase. The Standards Committee agreed at its July 2008 meeting and the standards were posted for a 30-day pre-ballot phase on August 13, 2008. The initial ballot was conducted from September 11–22, 2008. A total of 79.74 percent of the 153 ballot pool members participated in the ballot and voted unanimously for the standards, with 15 abstentions. No recirculation ballot was required.

The drafting team made the following revisions to the standards in this proposed Version 3:

- The timing tables were split into a WECC-specific table and an Eastern/ERCOT/Hydro-Quebec specific table to provide better understanding of the timing requirements.
- The timing tables reintroduce the time classifications of "late" and "on-time" and include a designation for the new "After the Fact" time classification for all Interconnections. These classifications are consistent with the existing e-Tag implementation.
- The timing table for WECC includes the modification to allow reliability entities up to 10 minutes for reliability assessment in most cases while still allowing for on-time submittal of e-Tags up to 20 minutes prior to the operating hour (per the urgent action process changes.)
- A change was made to R1 of INT-006 clarifying applicability to "on-time" requests for interchange. Corresponding changes to the measure were made in response to comments.

- Additional clarification was added to the requirements and timing tables in response to industry comments.
- The “Minimum Total Reliability Period” column has been deleted from the tables as it did not add any benefit and its removal makes the tables clearer.
- Added new definitions for After-the-Fact, Emergency RFI (Request for Interchange), and Reliability Adjustment RFI.

These standards are proposed to become effective the first day of the first calendar quarter at least three months from all regulatory approvals.

d. Status of Standards Development — Information Only

Regulatory Status
In the United States, NERC has received approval for 94 continent-wide reliability standards and 8 WECC regional standards. An additional 24 standards ("fill-in-the-blank") are still held as pending further information per Order No. 693. On July 21, 2008, FERC approved the following revised standards:

- INT-001-3 — Interchange Information
- INT-004-2 — Dynamic Interchange Transaction Modifications
- INT-005-2 — Interchange Authority Distributes Arranged Interchange
- INT-006-2 — Response to Interchange Authority
- INT-008-2 — Interchange Authority Distributes Status

In addition, FERC asked for further clarification regarding the proposed IRO-006-4 — Transmission Loading Relief standard. NERC issued its response to FERC's questions in September 2008.

In addition, FERC has proposed to approve through its Notice of Proposed Rulemaking (NOPR) process, NUC-001-1 — Nuclear Plant Interface Coordination.

Since the July 2008 board meeting, NERC staff and the leadership of the respective standard drafting teams have met with FERC staff in support of the request for pre-filing meetings as follows:

- Project 2006-03 — System Restoration and Blackstart
- Project 2006-06 — Reliability Coordination
- Project 2006-07 — ATC-Related Standards
- Project 2006-09 — Facility Ratings
- Project 2007-04 — Certifying System Operators
- Project 2007-06 — System Protection Coordination
- Project 2007-07 — Vegetation Management
- Project 2007-17 — Protection System Maintenance and Testing
- WECC Tier 1 Regional Standards

Also since the last board meeting, the following regulatory filings have been made:

- Nine missing Violation Risk Factors for Critical Infrastructure Protection standards on July 30, 2008;
- Five ATC-related reliability standards on August 29, 2008;
- PRC-023-1 — Transmission Relay Loadability on July 30, 2008;
- TOP-004-2 — Transmission Operations on July 28, 2008;
- BAL-004-WECC-01 — Automatic Time Error Correction on July 29, 2008; and,
- IRO-005-2 — Reliability Coordination – Current-Day Operations on July 28, 2008.

Standards Under Development
Key standards that are nearing completion are:

System Personnel Training (Project 2006-01) — this proposed standard would establish new requirements for the development, implementation, and maintenance of system personnel training programs. The first draft of the standard was posted in September 2006. The second draft was posted for comment from August 15–September 28, 2007. The third draft was posted from February 25–April 8, 2008. The fourth and final draft was posted from June 18–July 17, 2008. The team does not believe that further consensus is achievable while industry concern remains on the use of the systematic approach to training and the use of simulation training, both topics included in the standard to address FERC directives from Order No. 693. At its September 2008 meeting, the Standards Committee approved the standard to proceed to the ballot phase.

Status — The proposed standard proceeded to the pre-ballot phase at the end of September. The initial ballot is projected to begin on October 27, 2008 with overall completion projected for the end of the year.

Operate Within Interconnection Reliability Operating Limits — the standard drafting team reviewed FERC Order No. 693 with respect to the IROL standards that were posted for pre-ballot review and noted that there were some directives that were not met with the proposed standards. In May 2007 the Standards Committee authorized the team to consider additional changes to the standards and the associated implementation plan and post the revisions for another comment period before proceeding to the ballot stage. The standards, coupled with the system operating limits approved by the board in November 2006 will provide for consistent determination of limits for operation of the bulk power system.

Status — In August the standards passed the ballot successfully and are being presented for NERC board approval in October.

ATC-Related Standards (Project 2006-07) — these proposed set of standards address the methodology and components to calculate available transfer capability. These standards are the focal point of FERC's open access transmission tariff reform Order No. 890 in which it specifies improvements that will make these calculations more open and transparent. These improvements will thereby eliminate the potential for discretionary practices when calculating transfer capability for native load versus commercial uses of the transmission grid. FERC has set a December 2007 deadline for completion of these standards.

In late May, the standard drafting team produced its first draft of all affected ATC standards (MOD-001 through MOD-009) for a 30-day comment period. The team received over 120 sets of comments from industry stakeholders that it considered in a series of meetings throughout the summer and early fall. The team posted its second draft of ATC standards in October and received a large number of comments in response.

In November 2007, NERC requested, and FERC approved, an extension for delivery of these ATC standards until May 9, 2008. To support the drafting team's opportunity to meet this deadline, at the December 2007 Standards Committee meeting they approved the drafting team submitting the standards for ballot without an additional comment period as a result of the fall 2007 posting. The Standards Committee also agreed to utilize multiple initial ballots as necessary without additional industry comment periods.

The drafting team made significant changes to the set of standards as result of the fall 2007 deadline. In an effort to meet the May 9, 2008 deadline, the team requested and received Standards Committee approval to move to the ballot phase without industry comment. The initial ballot on the six ATC-related reliability standards was conducted from March 3–12, 2008. Each of the proposed standards achieved the necessary 75 percent quorum of ballot pool participants but failed to reach the required two-thirds weighted segment approval needed for presentation to the board. Among many technical comments, a significant number of commenters noted that the failure to allow the industry to comment on the standards that were changed significantly from the previous posting was a reason for their negative votes.

In light of the commentary regarding industry comment and the further changes that were made as a result of the ballot comments, the drafting team recommended that the proposed set of standards be presented for industry comment and allow the full effect of the Reliability Standards Development Procedure to take its course. NERC staff concurred with this approach and requested FERC to further extend its ATC-standards deadline. For five of the six ATC standards, NERC requested an extension to August 29, 2008. The sixth standard, dealing with Capacity Benefit Margin, requires more significant technical revision and is proposed to be delivered by November 21, 2008. After discussing the current status of activities with FERC staff on April 3, 2008, NERC filed its request for extension on April 17, 2008.

The drafting team completed its development of the five standards and they were posted for pre-ballot review on June 20, 2008. The five standards received sufficient approval percentage for passage on recirculation after considerable industry discussion on MOD-030-1 following the initial ballot. MOD-030-1 did not receive sufficient support for passage in the initial ballot. The drafting team reached a compromise solution with the stakeholders that resulted in the immediate development of version 2 of MOD-030 to better address the comments associated with the negative votes. As a result, MOD-030-1 received sufficient support for passage during the recirculation ballot. These five standards were filed without Violation Risk Factors (VRFs) on August 29, 2008. The board asked NERC staff to review the VRF assignments for the five standards relative to previous Commission action on VRF assignments, and to better define a "direct impact to the bulk power system" that would be a necessary criteria for assignment of a Medium VRF. NERC staff should present its recommendations to the board when it completes its review.

Status — The sixth ATC standard, MOD-004-1 pertaining to Capacity Benefit Margin was posted for a 30-day comment period that ended on June 23, 2008. The team responded to comments and requested approval from the Standards Committee to proceed to the ballot phase. The Standards Committee agreed and the standard entered the 30-day pre-ballot phase on August 12, 2008. The initial ballot concluded on September 21, 2008 with the proposed standard falling just short of the required approval percentage (66.29 percent). The team is working with industry stakeholders to respond to their comments with the expectation to receive the needed support sufficient for passage. The team expects to proceed to the recirculation ballot at the end of October with November 21, 2008 as the required Commission filing deadline.

Facilities Ratings (Project 2006-09) — this project resolves a proposed directive for improvement in the facility ratings standards FAC-008 — Facility Ratings Methodology and FAC-009 — Establish and Communicate Facility Ratings. The second version of the SAR and proposed revisions to the standards, including changes driven by FERC Order No. 693, were posted from July 19–August 17, 2008.

Status — The drafting team met with FERC staff to discuss the final edits and posted the standards for its final comment period that concluded on August 26, 2008. The Standards Committee approved the standards to proceed to the balloting phase at its September meeting. The standard is currently posted for pre-ballot review with the initial ballot expected to begin the last week of October. Completion is anticipated by the end of 2008.

In addition to these key projects, the following summarizes the status of the remaining standards under development:

- Project 2006-02 — Assess Transmission Future Needs and Develop Transmission Plans: the second posting of the proposed standards concluded in late September 2008. The team is contemplating the comments.
- Project 2006-03 — System Restoration and Blackstart: the third posting of the proposed standards ended in late May 2008. The team is reviewing and developing responses to comments.
- Project 2006-04 — Backup Facilities: the drafting team posted its second draft for comment through October 9, 2008. The team is set to review the comments and respond to these comments once collected.

e. Consideration of WECC Tier 1 Reliability Standards — Approve

Approve, with conditions, the following five Western Electricity Coordinating Council (WECC) Regional Reliability Standards:

FAC-501-WECC-1 — Transmission Maintenance
PRC-004-WECC-1— Protection System and Remedial Action Scheme Misoperation
TOP-007-WECC-1 — System Operating Limits
VAR-002-WECC-1 — Automatic Voltage Regulators
VAR-501-WECC-1 — Power System Stabilizer

Remand the following two WECC Regional Reliability Standards:

BAL-002-WECC-1 — Contingency Reserves
IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

The five standards submitted for board approval will not become effective under Section 215 of the U.S. Federal Power Act until they have also been approved by the Federal Energy Regulatory Commission (FERC).

The reliability of the bulk power system of the Western Interconnection is best served by the implementation of the five Regional Reliability Standards in question. These five Regional standards replace six WECC Regional standards approved by FERC in June 2007. In the interest of improved reliability, NERC staff recommends Board of Trustee approval of the five WECC Regional Reliability Standards, under the following condition:

- WECC shall address the shortcomings identified in these five standards during the next revision of the standards.

Proposed WECC reliability standard BAL-002-WECC-1 — Contingency Reserves lacks technical support for a key requirement change and on this basis, the proposed standard should be remanded by the board until further technical justification is provided. If WECC determines a change is required to the proposed regional standard it should also include language that clearly permits the use of demand-side resources for spinning reserve, provided these resources meet the same performance expectations to those utilized in practice today for spinning reserve. This proposed change ensures conformance of the standard to FERC's Order No. 693 with respect to demand-side resources. However, if no change to the standard is required WECC should address this issue at the next opportunity for revisions.

Proposed WECC reliability standard IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief does not meet the statutory criteria for a Regional Reliability Standard and should be remanded on this basis.

Detailed descriptions of each of these Regional Reliability Standards are found as **Attachments 1–7**. A summary of conclusions and recommendations for each proposed standard is found at the end of this document.

Background
On June 8, 2007, FERC approved, with conditions, eight WECC Tier 1 Reliability Management System (RMS) Regional Reliability Standards stating that the reliability of the bulk power system of the Western Interconnection is best served by their implementation. These standards are:

- BAL-STD-002-0 — Operating Reserves
- IRO-STD-006-0 —Qualified Path Unscheduled Flow Relief
- PRC-STD-001-1 — Certification of Protective Relay Applications and Settings
- PRC-STD-003-1 — Protective Relay and Remedial Action Scheme Misoperation
- PRC-STD-005-1 — Transmission Maintenance
- TOP-STD-007-0 — Operating Transfer Capability
- VAR-STD-002a-1 — Automatic Voltage Regulators
- VAR-STD-002b-1 — Power System Stabilizers

WECC, supported by the Western Interconnection Regional Advisory Body (WIRAB), identified these Regional standards as essential and necessary for the reliable operation of the Western Interconnection. The majority of these standards were specifically developed to address and mitigate the main causes of two major system outages that occurred in the Western Interconnection in July and August of 1996.

In June 2008, WECC submitted seven proposed Regional Reliability Standards to replace the eight original standards approved in 2007. WECC used its approved Process for Developing and Approving WECC Standards in developing these proposed standards. Further, WECC satisfied the conditions under which the original standards were proposed. In addition, WECC made changes beyond the FERC and NERC directives that, in some cases, reduce the stringency of the current approved versions. However, NERC's responsibility in considering proposed Regional standards is to ensure the standards meet the statutory criteria to be approved.

A reliability standard proposed by a Regional Entity must meet the same standards NERC's Reliability Standards must meet, i.e., the Regional Reliability Standard must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[1] If the Regional Standard is proposed by a Regional Entity organized on an interconnection-wide basis to be applicable on an interconnection-wide basis, then NERC must rebuttably presume the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[2]

FERC Order No. 672 establishes two additional criteria that a Regional standard must satisfy. A Regional difference from a continent-wide reliability standard must either be (1) more stringent than the continent-wide reliability standard (which includes a Regional Reliability Standard that addresses matters that the continent-wide reliability standard does not), or (2) a Regional Reliability Standard that is necessitated by a physical difference in the bulk-power system.[3] Rule 312 of NERC's Rules of Procedure establishes other factors for the board to consider in acting on a request to approve such proposals. The board must consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to approve the Regional Reliability Standard as a NERC Reliability Standard.[4]

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[1] Section 215(d)(2) of the Federal Power Act and §39.5(a) of the Commission's regulations.
[2] Section 215(d)(3) of the Federal Power Act and §39.5(b) of the Commission's regulations.
[3] Order No. 672, Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, P 291.
[4] NERC Rules of Procedure, § 312.3.1.

WECC is a Regional Entity organized on an interconnection-wide basis, and the proposed Regional Reliability Standards are to be applicable on an interconnection-wide basis. Considering the proposed standards on their merits NERC staff finds that, with the two exceptions noted for BAL-002-WECC-1 — Contingency Reserves and IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief, the proposed standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest, and the proposed WECC Regional Standards meet the criteria for consideration and approval as a Regional Reliability Standard.

Procedurally, WECC states it followed its Process for Developing and Approving WECC Standards, and no commenter disagreed, although some raised the concern about the openness of the process. NERC confirmed that WECC followed its approved process per its Regional Delegation Agreement with NERC.

NERC staff affords due weight to WECC's technical expertise in the development of reliability standards applicable within the Western Interconnection, and absent strong technical objection from commenters, NERC will not second-guess the technical merits of the proposed Regional Reliability Standards. They were developed by those from the Western Interconnection, to apply in the Western Interconnection, in a process that enabled all those with an interest in the standards to be heard. NERC's public posting of the proposed Regional Reliability Standards did not elicit any significant technical objection, with the exception of BAL-002-WECC-1 — Contingency Reserves. On this basis, NERC staff determined there was sufficient merit to challenge the WECC presumption of validity for BAL-002-WECC-1, and as a result, recommends the standard be remanded to enable WECC to provide further technical support for the change in certain requirements.

Summary Conclusions and Recommendations

FAC-501-WECC-1 — Transmission Maintenance

- NERC recommends the approval of FAC-501-WECC-1 — Transmission Maintenance on the basis that the Regional Reliability Standard addresses matters that the continent-wide NERC Reliability Standards do not, thus satisfying the statutory criteria for a Regional Reliability Standard.
- FAC-501-WECC-1 requires, for specified transmission paths, a highly detailed maintenance and inspection plan for all transmission and substation equipment components, well beyond the relay and communication system maintenance and testing requirements in continent-wide NERC Reliability Standards.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

- NERC recommends approval of PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation and four associated definitions on the basis that the Regional Reliability Standard is more stringent than the corresponding NERC Reliability Standard, PRC-004-1, thus satisfying the statutory criteria for a Regional Reliability Standard.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.

- NERC also found that WECC adequately addressed the FERC and NERC directives.

TOP-007-WECC-1 — System Operating Limits

- NERC recommends approval of TOP-007-WECC-1 — System Operating Limits on the basis that the Regional Reliability Standard is more stringent than the corresponding NERC Reliability Standard, TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations, thus satisfying the statutory criteria for a Regional Reliability Standard. The 30-minute response limit to SOL violations is more stringent than the corresponding NERC Reliability Standard.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

VAR-002-WECC-1 — Automatic Voltage Regulators

- NERC recommends approval of VAR-002-WECC-1 — Automatic Voltage Regulators (AVRs) and associated definition, "Commercial Operation" on the basis that the Regional Reliability Standard is more stringent than the continent-wide NERC Reliability Standard VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules, thus satisfying the statutory criteria for a Regional Reliability Standard.
- The continent-wide NERC Reliability Standard VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules requires that a generator operator operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator. VAR-002-WECC-1, R1 requires all synchronous generators to have their voltage regulator in service at all times with only exceptions for specified circumstances, making it more stringent than NERC's standard.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

VAR-501-WECC-1 — Power System Stabilizer

- NERC recommends approval of VAR-501-WECC-1 — Power System Stabilizer and associated definition, "Commercial Operation" on the basis that the Regional Reliability Standard addresses matters that the continent-wide NERC Reliability Standards do not, thus satisfying the statutory criteria for a Regional Reliability Standard.
- VAR-501-WECC-1 — Power System Stabilizer ensures Power System Stabilizers (PSS) on synchronous generators shall be kept in service, which far exceeds the specificity in the continent-wide NERC Reliability Standard, VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

BAL-002-WECC-1 — Contingency Reserves

- BAL-002-WECC-1 — Contingency Reserves contains requirements that are more stringent than continent-wide NERC Reliability Standards and cover matters not covered by NERC's Reliability Standards, thereby justifying its consideration as a Regional Reliability Standard.
- Several commenters offered challenges to the technical basis for the change in contingency reserve assignments and allocations. These challenges serve to rebut the presumption of validity for WECC as a Regional Entity organized on an Interconnection-wide basis. On this basis, NERC staff recommends the proposed Regional standard be remanded to establish a more sufficient technical justification for the change in Requirement R1.1.2.
- Until NERC's definition of Spinning Reserve is revised to allow for the use of resources other than generation, WECC should propose a modification to the proposed standard that permits the use of demand side resources in all facets of contingency reserve, including spinning reserve, provided the demand side resources meet performance requirements comparable to generation resources used for the same purpose. This will ensure the standard is consistent with FERC Order No. 693 in this regard.
- Consider incorporating suggestions for improving the standard offered in NERC's evaluation.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

- NERC recommends IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief be remanded as it is no longer more stringent than the corresponding NERC Reliability Standard.
- The proposed standard IRO-006-WECC-1 is proposed on the basis that it is more stringent than existing NERC Reliability Standards and is necessary as the only source of a mandatory process for mitigating overloads due to unscheduled flows in the Western Interconnection. While WECC made very useful conforming changes to the existing FERC-approved standard, IRO-STD-006-0, that clarify the applicable entities and eliminate the inclusion of entities (for example Load Serving Entities) that may not have the ability to ensure mitigation of overloads as specified in the FERC and NERC directives, the replacement standard no longer presents a comprehensive approach for mitigation of transmission overloads due to unscheduled flow.
- Although WECC adequately addressed the NERC and FERC directives, the additional changes made are problematic. As a result of these changes, the proposed Regional Reliability Standard no longer references WECC's Unscheduled Flow Mitigation Plan that contains directions to reduce flows that include phase-angle-regulators, series capacitors, and back-to-back DC lines before transaction curtailment. These aspects originally made the currently approved version of the standard superior to the NERC Reliability Standard. This is no longer the case.
- Furthermore, the proposed Regional Reliability Standard is inconsistent with the standard's purpose, "to mitigate transmission overloads due to unscheduled flow" and the corresponding continent-wide NERC Reliability Standard that currently references the entire WECC unscheduled flow mitigation plan as it eliminates the requirements to implement coordinated action per steps 1–3 in the plan.
- R1, which requires Reliability Coordinators to respond to a Transmission Operator's request for relief within five minutes and R2, which requires Balancing Authorities implement the

request to provide relief should be included as a Regional Variance to the NERC Reliability Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief. These requirements propose alternate activities to that of the continent0-wide requirements and support the reliability objective of the continent-wide standard. This is in alignment with the NERC definition of a Regional Variance as stated in Section 202 of the Rules of Procedure[5].

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5 Variance means an aspect or element of a reliability standard that applies only within a particular regional entity or group of regional entities, or to a particular entity or class of entities. A variance allows an alternative approach to meeting the same reliability objective as the reliability standard, and is typically necessitated by a physical difference. A variance is embodied within a reliability standard and as such, if adopted by NERC and approved by the ERO governmental authority, shall be enforced within the applicable regional entity or regional entities pursuant to delegated authority.

FAC-501-WECC-1 — Transmission Maintenance

Action: FAC-501-WECC-1 — Transmission Maintenance — **Approve**

Proposed Effective Date: On the first day of the first quarter, after applicable regulatory approval.

Summary Conclusion and Recommendation:

- NERC recommends the approval of FAC-501-WECC-1 — Transmission Maintenance on the basis that the Regional Reliability Standard addresses matters that the continent-wide NERC Reliability Standards do not, thus satisfying the statutory criteria for a Regional Reliability Standard.
- FAC-501-WECC-1 requires, for specified transmission paths, a highly detailed maintenance and inspection plan for all transmission and substation equipment components, well beyond the relay and communication system maintenance and testing requirements in continent-wide NERC Reliability Standards.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

Background*:* WECC-PRC-STD-005-1 — Transmission Maintenance ensures that the "Transmission Operator or Owner of a transmission path identified in Attachment A to the standard perform maintenance and inspection on identified paths as described by its transmission maintenance plan." PRC-STD-005-1 contains maintenance requirements not covered in the continent-wide NERC Reliability Standards thereby satisfying the statutory criteria for consideration as a Regional Reliability Standard. NERC's Reliability Standard PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing has requirements for equipment maintenance and inspection of relay and backup power systems. FAC-003-1 — Transmission Vegetation Management Program has requirements for vegetation management. However, the NERC Reliability Standards do not have any maintenance and testing requirements for the additional components such as breakers, reactive devices, transformers and associated transmission lines.

On June 8, 2007 FERC approved eight WECC Regional Reliability Standards that included WECC-PRC-STD-005-1 – Transmission Maintenance. In the order approving the standards, FERC directed WECC to make conforming changes to the standard based on the shortcomings identified in NERC's evaluation of the standard, as follows:

1. Remove the sanctions table that is inconsistent with the NERC Sanction Guidelines and add Violation Risk Factors and Violation Severity Levels;
2. Consider re-writing the requirements to express one main idea in each requirement; and
3. Conform the standard to the form of NERC Reliability Standards with respect to the effective date, stating it should become effective on the first day of following quarter upon regulatory approval.

Further, FERC supported NERC's conditions for approval that WECC meet its commitment to address the shortcomings over the course of the year.

Proposal FAC-501-WECC-1 — Transmission Maintenance: The proposed Regional Reliability Standard, FAC-501-WECC-1, was submitted to NERC on June 11, 2008 for approval. This standard is intended to replace the FERC-approved WECC-PRC-STD-005-1. In processing the proposed Regional Reliability Standard, WECC indicated it utilized its standards development procedure that existed at the time per its Regional Delegation Agreement with NERC.

The proposed replacement standard, FAC-501-WECC-1, was modified such that it no longer contains the sanctions table; includes Violation Severity Levels, Violation Risk Factors, measures and time horizons; conforms the effective date format to that of the NERC Reliability Standards; conforms the overall format of the standard to that of the NERC Reliability Standards; and clarifies the requirements as suggested by NERC.

In addition to the directed changes, WECC made other modifications to the standard not directed by FERC or NERC:

- WECC modified the applicability of the standard to apply to Transmission Owners that maintain the transmission paths in the most current table: "Major WECC Transfer Paths in the Bulk Electric System". WECC-PRC-STD-005-1 applied to Transmission Owners in addition to Transmission Operators.
- WECC removed the transmission line and station maintenance details (Transmission Maintenance and Inspection Plan contents) from the body of the standard (formerly Requirement WR1.b) to an Attachment 1 of standard FAC-501-WECC-1.
- WECC-PRC-STD-005-1, M1 required the responsible entity to maintain records of all maintenance and inspection activities for at least five years. The wording of the data retention requirement was modified in FAC-501-WECC-1 to specify transmission owners shall keep evidence for M1–M3 for three years plus the current year, or since the last audit, whichever is longer. WECC explains this modification was made to ensure data are kept in a contiguous manner between audit periods.

NERC 45-Day Posting: Upon WECC board action in April 2008, WECC submitted its seven proposed Tier 1 Regional Reliability Standards to NERC for the required 45-day public posting that took place from April 4–May 20, 2008. The proposed Regional Reliability Standards received two minor comments during the NERC posting. WECC supplied NERC with its response to comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received.

NERC Evaluation: In accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*, approved by the Regional Reliability Standards Working Group, NERC provided its evaluation of the proposed standard FAC-501-WECC-1 to WECC on July 30, 2008 (Appendix 4). In this report NERC made several recommendations to the proposed standard FAC-501-WECC-01 to which WECC responded in an August 18, 2008 letter (Appendix 5):

- NERC suggested WECC add a table containing the Violation Severity Levels to conform to the NERC Reliability Standards. WECC agreed that the proposed Violation Severity Levels in FAC-501-WECC-1 are inconsistent in format with that of the NERC Reliability Standards.

- NERC also suggested capitalizing references to defined terms throughout the standard. WECC clarified that the terms used in the standard do not have corresponding entries in the NERC Glossary of Terms and did not intend on proposing a new defined term for transmission facilities ("Transmission" and "Facilities" are in the NERC Glossary of Terms but "Transmission Facilities" is not in the NERC Glossary of Terms).

NERC staff believes WECC responded adequately to NERC's suggestions by agreeing to conform the Violation Severity Levels format to that of the NERC Reliability Standards in a revision to the standard. In addition, FERC staff expressed a concern with FAC-501-WECC-01 that it is not clear whether the proposed standard reduces the number of lines that are subject to this standard as compared to the current version. WECC clarified that the number of lines or facilities subject to the proposed standard has not changed and can be found in the referenced link in the Applicability section of the proposed standard.

Supporting Documents:

- Appendix 1 — Regional Reliability Standard Submittal Request
- Appendix 2 — Standard Development Roadmap
- Appendix 3 — Consideration of Comments document on NERC's posting of the regional standard
- Appendix 4 — NERC Evaluation of WECC Regional Standards
- Appendix 5 — WECC Response to NERC Evaluation
- Appendix 6 — WECC Response to FERC Comments
- Appendix 7 — WECC Consideration of Comment Reports
- Appendix 8 — WECC Standards Drafting Team
- Appendix 9 — WECC Balloting

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standard Submittal Request

Region: Western Electricity Coordinating Council

Regional Standard Number: FAC-501-WECC-1

Regional Standard Title: Transmission Maintenance

Date Submitted: June 10, 2008

Regional Contact Name: Steven L. Rueckert

Regional Contact Title: Director of Standards

Regional Contact Telephone Number: (801) 582-0353

Request (check all that apply):

- ☒ Approval of a new standard
- ☐ Revision of an existing standard
- ☒ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

- ☒ Yes April 16, 2008
- ☐ No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:

The purpose of this standard is to create a permanent replacement standard for PRC-STD-005-1. In response to comments, the drafting team changed the name of the standard from PRC-005-WECC-1 to FAC-501-WECC-1 to better align with the NERC numbering system. FAC-501-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when PRC-STD-005-1 was approved as a NERC reliability standard.

To page 1 resource links

Concise statement of the justification of the request:

The FAC-501-WECC-1 regional reliability standard contains maintenance requirements not covered in the continent-wide reliability standards. The NERC standard PRC-005-1 has requirements for equipment maintenance and inspection of relay and backup power systems. FAC-003-1 has requirements for vegetation management. The NERC standards do not have any maintenance and test requirements for the additional components such as breakers, reactive devices, transformers and the associated transmission line. The 40 major paths listed in the Attachment 1-FAC-501-WECC-1 are significant components for reliable delivery of power in the Western Interconnection. Breaker, transformer, and insulator failures cause reductions to the System Operating Limits (SOL) for those paths, and thus limit transfers between remotely located generation in the Western Interconnection and population/load centers. The entities of the Western Interconnection through study and operation see optimizing the capacity for these paths as critical to the reliability of the Western Interconnection. The lack of redundant transmission in these corridors raises the level of scrutiny for the components and facilities associated with these paths; therefore, this standard is designed to minimize the SOL reductions required to maintain reliable Western Interconnection operation.

Other — please attach or include as separate files:

- The text of the regional reliability standard in MS Word format that:
    - has either been, or is anticipated to be, approved by the regional entity's board, and
    - is in a format consistent with the NERC template for reliability standards.
- An implementation plan.
- The regional entity standard drafting team roster.
- The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.
- The final ballot results, including a list of significant minority issues that were not resolved, and
- For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.

Appendix 2

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

Completed Actions	Completion Date
1. Post Draft Standard for initial industry comments	September 4, 2007
2. Drafting Team to review and respond to initial industry comments	November 1, 2007
3. Post second Draft Standard for industry comments	November 9, 2007
4. Drafting Team to review and respond to industry comments	January 7, 2008
5. Post Draft Standard for Operating Committee approval	January 17, 2008
6. Operating Committee approved proposed standard	March 6, 2008
7. Post Draft Standard for WECC Board approval	March 12, 2008
8. Post Draft Standard for NERC comment period	April 14, 2008
9. WECC Board approved proposed standard	April 16, 2008
10. NERC comment period ended	May 20, 2008
11. Drafting Team completes review and consideration of NERC industry comments	May 30, 2008

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for PRC-STD-005-1. In response to comments, the drafting team changed the name of the standard from PRC-005-WECC-1 to FAC-501-WECC-1 to better align with the NERC numbering system. FAC-501-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when PRC-STD-005-1 was approved as a NERC reliability standard. This version of the FAC-501-WECC-1standard is for NERC Board of Trustee ballot. The WECC Board of Directors approved the standard April 16, 2008. WECC Operating Committee approved the standard March 6, 2008. The WECC Board of Directors and Operating Committee request that the NERC Board of Trustees approve the FAC-501-WECC-1 Standard as a permanent replacement standard for PRC-STD-005-1 and that the NERC Board of Trustees submits the standard to FERC for approval and replacement of PRC-STD-005-1.

Justification for a Regional Standard

The NERC standard PRC-005-1 has requirements for equipment maintenance and inspection of relay and backup power systems. FAC-003-1 has requirements for vegetation management. The NERC standards do not have any maintenance and test requirements for the additional components such as breakers, reactive devices, transformers and the associated transmission line. The 40 major paths listed in the Attachment 1-FAC-501-WECC-1 are significant components for reliable delivery of power in the Western Interconnection.

Breaker, transformer, and insulator failures cause reductions to the System Operating Limits (SOL) for those paths, and thus limit transfers between remotely located generation in the Western Interconnection and population/load centers. The entities of the Western Interconnection through study and operation see optimizing the capacity for these paths as critical to the reliability of the Western Interconnection. The lack of redundant transmission in these corridors raises the level of scrutiny for the components and facilities associated with these paths; therefore, this standard is designed to minimize the SOL reductions required to maintain reliable Western Interconnection operation.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. NERC Board approval request	June 2008
2. Request FERC approval	June 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

A. Introduction

1. **Title:** Transmission Maintenance

2. **Number:** FAC-501-WECC-1

3. **Purpose:** To ensure the Transmission Owner of a transmission path identified in the table titled "Major WECC Transfer Paths in the Bulk Electric System" including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.

4. **Applicability**

4.1. Transmission Owners that maintain the transmission paths in the most current table titled "Major WECC Transfer Paths in the Bulk Electric System" provided at:

http://www.wecc.biz/Docs/Documents/Table%20Major%20Paths%204-28-08.doc.

5. **Effective Date:** On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R.1. Transmission Owners shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled "Major WECC Transfer Paths in the Bulk Electric System." *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R1.1. Transmission Owners shall annually review their TMIP and update as required. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R.2. Transmission Owners shall include the maintenance categories in Attachment 1-FAC-501-WECC-1 when developing their TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R.3. Transmission Owners shall implement and follow their TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

C. Measures

M1. Transmission Owners shall have a documented TMIP per R.1.

M1.1 Transmission Owners shall have evidence they have annually reviewed their TMIP and updated as needed.

M2. Transmission Owners shall have evidence that their TMIP addresses the required maintenance details of R.2.

M3. Transmission Owners shall have records that they implemented and followed their TMIP as required in R.3. The records shall include:

1. The person or crew responsible for performing the work or inspection,
2. The date(s) the work or inspection was performed,
3. The transmission facility on which the work was performed, and
4. A description of the inspection or maintenance performed.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

The Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Self-certification conducted annually
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be one year.

1.3 Data Retention

The Transmission Owners shall keep evidence for Measure M1 through M3 for three years plus the current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

No additional compliance information.

2. Violation Severity Levels

2.1. Lower: There shall be a Lower Level of non-compliance if any of the following conditions exist:

2.1.1 The TMIP does not include associated Facilities for one of the Paths identified in Attachment 1 FAC-501-WECC-1 as required by R.1 but Transmission Owners are performing maintenance and inspection for the missing Facilities.

2.1.2 Transmission Owners did not review their TMIP annually as required by R.1.1.

2.1.3 The TMIP does not include one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.1.4 Transmission Owners do not have maintenance and inspection records as required by R.3 but have evidence that they are implementing and following their TMIP.

2.2. Moderate: There shall be a Moderate Level of non-compliance if any of the following conditions exist:

2.2.1 The TMIP does not include associated Facilities for two of the Paths identified in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System” as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.2.2 The TMIP does not include two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.2.3 Transmission Owners are not performing maintenance and inspection for one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.3. **High:** There shall be a High Level of non-compliance if any of the following condition exists:

2.3.1 The TMIP does not include associated Facilities for three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.3.2 The TMIP does not include three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.3.3 Transmission Owners are not performing maintenance and inspection for two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.4. **Severe:** There shall be a Severe Level of non-compliance if any of the following condition exists:

2.4.1 The TMIP does not include associated Facilities for more than three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.4.2 The TMIP does not exist or does not include more than three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.4.3 Transmission Owners are not performing maintenance and inspection for more than two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-005-1	

Attachment 1-FAC-501-WECC-1
Transmission Line and Station Maintenance Details

The maintenance practices in the TMIP may be performance-based, time-based, conditional based, or a combination of all three. The TMIP shall include:

1. A list of Facilities and associated Elements necessary to maintain the SOL for the transfer paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System;"
2. The scheduled interval for any time-based maintenance activities and/or a description supporting condition or performance-based maintenance activities including a description of the condition based trigger;
3. Transmission Line Maintenance Details:
   a. Patrol/Inspection
   b. Contamination Control
   c. Tower and wood pole structure management
4. Station Maintenance Details:
   a. Inspections
   b. Contamination Control
   c. Equipment Maintenance for the following:
      - Circuit Breakers
      - Power Transformers (including phase-shifting transformers)
      - Regulators
      - Reactive Devices (including, but not limited to, Shunt Capacitors, Series Capacitors, Synchronous Condensers, Shunt Reactors, and Tertiary Reactors)

Appendix 3

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Report Form for WECC Standard FAC-501-WECC-1 — Transmission Maintenance

The FAC-501-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the FAC-501-WECC-1 Standard. This Standard was posted for a 45-day public comment period from April 4, 2008 through May 20, 2008. NERC distributed the notice for this posting on April 7, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were three sets of comments from five companies representing four of the ten Industry Segments as shown in the table on the following pages.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the Standard can be viewed in their original format at:

http://www.nerc.com/~filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Manager of Regional Standards, Stephanie Monzon at Stephanie.monzon@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is described in the NERC Regional Reliability Standards Development Procedure: ftp://www.nerc.com/pub/sys/all_updl/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Denise Koehn	Bonneville Power Administration	✓		✓		✓	✓				
2.	Annette Bannon	PPL Generation, LLC					✓	✓				
3.	Jon Williamson	PPL EnergyPlus						✓				
4.	John Cummings	PPL EnergyPlus						✓				
5.	Tom Olson	PPL Montana, LLC					✓					
6.	Paul Mueller	Arizona Public Service, T&D Reliability Analysis and Management	✓									

Index to Questions, Comments, and Responses

1. **Was the WECC Standard FAC-501-WECC-1 – Transmission Maintenance developed in a fair and open process, using the Process for Developing and Approving WECC Standards?**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn	X		
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson	X		PPL believes that this revision of the standard adds valuable language to help make the grid more reliable.
Response: Thank you.			
Paul Mueller	X		General review comments: Now that the procedure references the WECC Web page for the transmission paths, it is more dynamic and will necessitate more periodic reviews. Whenever the Web page is revised beyond simple editorial changes we would expect notification. What is the intent of changing D.1.1 from "WECC" to "Compliance Enforcement Agency"? Does this defer to NERC?
Response: Modifications to the table titled “Major WECC Transfer Paths in the Bulk Electric System” are to be developed using the "Process for Developing and Approving WECC Standards." The refinements would require posting for comment, OC approval, and WECC Board approval. However, NERC and FERC approval is not required. In the U.S. the "Compliance Enforcement Authority" is the Electric Reliability Organization (ERO). The "Compliance Enforcement Authority" outside of the U.S. has not been defined. In Canada, this may be the Provincial Regulators. The ERO in the U.S. is NERC. However, the Delegation Agreement transfers compliance enforcement to the regions. Therefore, in the U.S. the "Compliance Enforcement Authority" is a combination of WECC and NERC.			

2. **Does the WECC Standard FAC-501-WECC-1 – Transmission Maintenance pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

Commenter	Yes	No	Comment
Paul Mueller		X	
Response: Thank you.			

3. **Does the WECC Standard FAC-501-WECC-1 – Transmission Maintenance pose a serious and substantial threat to public health, safety, welfare, or national security?**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
Paul Mueller		X	
Response: Thank you.			

4. **Does the WECC Standard FAC-501-WECC-1 – Transmission Maintenance pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
Paul Mueller		X	
Response: Thank you.			

5. **Does the WECC Standard FAC-501-WECC-1 – Transmission Maintenance meet at least one of the following criteria?**

   - **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**

- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn	X		
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
Paul Mueller			
Response:			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Evaluation of Western Electricity Coordinating Council (WECC) Regional Standards

Executive Summary
July 30, 2008

On June 11, 2007, the WECC submitted the following seven regional standards for NERC evaluation to replace eight original WECC regional standards approved by NERC and FERC in 2007:

- BAL-002-WECC-1 — Contingency Reserves,
- FAC-501-WECC-1 — Transmission Maintenance,
- IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief,
- PRC-004-WECC-1— Protection System and Remedial Action Scheme Misoperation,
- TOP-007-WECC-1 — System Operating Limits,
- VAR-002-WECC-1 — Automatic Voltage Regulators and
- VAR-501-WECC-1 — Power System Stabilizer

NERC posted these seven proposed regional standards for a 45-day public posting beginning April 4–May 20, 2008. The standards received several comments during the NERC public posting. WECC supplied NERC with its responses to the comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting. WECC submitted these standards for NERC evaluation on June 11, 2008.

In accordance with NERC's *Rules of Procedure* and the *Regional Reliability Standards Evaluation Procedure* approved by the Regional Reliability Standards Working Group, NERC performed a review of the WECC proposed standards. The intent of this document is to provide WECC with NERC's feedback regarding their regional standards.

In this review, NERC presents a summary of observations for each proposed WECC regional standard. In Appendix A, NERC includes a redlined copy of each proposed regional standard with detailed comments included. NERC believes WECC has satisfied its procedural obligations as outlined in Appendix C of its Regional Delegation Agreement. However, NERC offers concerns and suggestions regarding several of the proposed regional standards that are discussed below.

Summary of Findings

BAL-002-WECC-1 — Contingency Reserves

In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

1. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

2. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

    R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

    R1.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

    R1.2. Capable of fully responding within ten minutes.

    In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

3. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

4. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

FAC-501-WECC-1 — Transmission Maintenance

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

1. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

2. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

1. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

2. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

3. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

1. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

2. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

3. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

4. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

TOP-007-WECC-1 — System Operating Limits

1. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

2. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

VAR-002-WECC-1 — Automatic Voltage Regulators

1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

   More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

VAR-501-WECC-1 — Power System Stabilizer

1. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a

justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

Conclusion

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC's Response to NERC's Comments
August 13, 2008
Draft

INTRODUCTION

WECC appreciates NERC staff's evaluation of the proposed WECC Regional Reliability Standards (RRSs) in accordance with NERC's Regional Reliability Standards Evaluation Procedure. These proposed WECC RRSs were developed as permanent replacements for the eight WECC Tier 1 RRSs that previously were approved by NERC and FERC. WECC asserts that the seven proposed standards contain all the performance elements of a Reliability Standard that are contained in the NERC Reliability Standards Development Procedure. In addition, the seven proposed standards address and implement the refinements directed by FERC's order on June 8, 2007 (see FERC Docket No.
RR07-11-000) and requested by NERC in its letter dated January 9, 2007. Finally, these proposed standards implement refinements to the approved WECC Tier 1 RRSs which were recommended during the previous expedited direct translation standard development processes.

The attached WECC responses individually address each NERC comment. However, many of the comments submitted by NERC staff relate to refinements that NERC has made to the format of its Reliability Standard Template. These refinements have not been formally approved by NERC, nor have they been transmitted to the regions for comment or additional information, and were therefore unavailable to WECC during the development process. Consequently, WECC has determined not to reopen the standards development process at this stage to address these non-substantive formatting concerns. In addition, during the standards development process, WECC staff twice requested that NERC staff review the proposed WECC standards. WECC did this to ensure that the WECC standard drafting teams were complying with NERC's Regional Reliability Standards Evaluation Procedure as well as its Reliability Standards Development Procedure. NERC did not perform the evaluation of these proposed standards until WECC had completed its Process for Developing and Approving WECC Standards. WECC intends to implement the requested formatting refinements and any potential FERC-directed changes during the next revision of these standards or the next FERC compliance filing.

The proposed WECC RRSs were considered and adopted pursuant to the Process for Developing and Approving WECC Standards. Unless they are approved in their current form, WECC will have to reinitiate the entire process. The consequences of rejecting these WECC RRSs in their entirety would be counterproductive to reliability in the Western Interconnection.

The proposed WECC RRSs will enhance reliability in the Western Interconnection and they will significantly improve the existing eight WECC RRSs because they:

1. Implement ordered NERC and FERC refinements to the existing standards ordered;
2. Eliminate conflicting NERC and WECC requirements contained in the existing RRSs;
3. Include all the Performance Elements of a Reliability Standard;
4. Clarify existing WECC RRSs;
5. Align better with NERC's Functional Model, and
6. Address industry stakeholder concerns.

Therefore, WECC requests the NERC staff recommend approval of these standards to the NERC Board and FERC.

WECC's responses to NERC's initial evaluation are provided in Attachment 1.

Attachment 1

NERC's Written Comments
July 30, 2008
WECC's Written Responses
August 13, 2008

Summary of Findings

BAL-002-WECC-1 — CONTINGENCY RESERVES

NERC COMMENT:
In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

5. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

WECC RESPONSE:
1. The requirements in the BAL-002-WECC-1 Standard as written are clear. Industry stakeholders did not submit any comments questioning the clarity of the standard, nor did they identify a need for an equation. The drafting team does not believe there is any ambiguity in the requirements.

NERC COMMENT:
6. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

> **R2.** Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
>
> **R2.1.** Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.
>
> **R2.2.** Capable of fully responding within ten minutes.

WECC RESPONSE:
2. The drafting team wrote the BAL-002-WECC-1 Standard to permit load, Demand-Side Management (DSM), generation, or another resource technology that qualifies as Spinning Reserve or Contingency Reserve to be used as such. In the case of DSM, the declared amount would be required to respond automatically to frequency deviations and be capable of fully responding in 10

minutes. Loads and DSM are not allowed as Spinning Reserve because it is not permitted by the NERC Spinning Reserve definition. NERC requires that the BAL-002-WECC-1 Standard drafting team use NERC's Spinning Reserve definition. If NERC were to modify its Spinning Reserve definition to allow frequency responsive load tripping as part of a Balancing Authority's DSM, then its use would be permitted under the requirements of the BAL-002-WECC-1 Standard as proposed.

NERC COMMENT (continued):

In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

WECC RESPONSE (continued):

DSM that is deployable within 10 minutes is a subset of Interruptible Load. Interruptible load is defined in requirement R3.2 as an acceptable type of Contingency Reserve. As described previously, if NERC modifies its Spinning Reserve and Interruptible Load definitions, then it would be clear that qualifying DSM is permitted as part of Spinning and Contingency Reserves.

NERC COMMENT:

7. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

WECC RESPONSE:

3. The drafting team wrote a paper titled "WECC Standard BAL-002-WECC-1 Contingency Reserves" that provides an explanation supporting the modification. The paper was included as part of the standards approval package filed on June 11, 2008 with NERC.

NERC COMMENT:

8. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

WECC RESPONSE:

4. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>FAC-501-WECC-1 — TRANSMISSION MAINTENANCE</u>

NERC COMMENT:

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

3. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

WECC RESPONSE:

1. "Transmission Facilities" is not a NERC-defined term in the NERC "Glossary of Terms Used in Reliability Standards" document, although "Transmission" and "Facility" are. The standard drafting team did not capitalize "transmission facilities" because it believes that the combination of these two defined terms was too limiting. WECC recognizes that this may create confusion and it proposes to address this issue during the next revision of these standards or the next FERC compliance filing.

NERC COMMENT:

4. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

2. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

IRO-006-WECC-1 — QUALIFIED TRANSFER PATH UNSCHEDULED FLOW (USF) RELIEF

NERC COMMENT:

4. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

WECC RESPONSE:

1. The proposed IRO-006-WECC-1 Standard contains all the key reliability requirements and technical elements from the Unscheduled Flow Mitigation Plan (UFMP) that were included in IRO-STD-006-0. The proposed IRO-006-WECC-1 Standard uses NERC's Functional Model terminology to mitigate unscheduled flow <u>during the next operating hour</u>. It is not necessary to reference the remainder of the UFMP because the remaining items contain procedural requirements explaining "how," not "what." The proposed IRO-006-WECC-1 Standard includes requirements to reduce schedules, which then require adjustments to generation patterns. This prevents potential overloads <u>during the next operating hour</u>. Importantly, the requirements for mitigation of an actual (real-time) overload are contained in TOP-007-WECC-1.

NERC COMMENT:

5. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC

proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

WECC RESPONSE:

2. WECC acknowledges the difference between the NERC and WECC definitions for Transfer Distribution Factor (TDF). This is caused by the differences between the Eastern Interconnection Transmission Loading Relief process and the Western Interconnection UFMP. This difference in definitions exists even today between the existing FERC-approved IRO-STD-006-0 Standard and the NERC Glossary. Rejecting the proposed standard will not resolve this difference. WECC will work with NERC to resolve this and intends to make any necessary refinements during the next revision of this standard or the next FERC compliance filing. Despite the difference in the TDF definitions, **the proposed standard corrects a basic difference between the existing FERC-approved IRO-STD-006-0 Standard, which places reliability responsibilities upon the Load Serving Entities (LSEs), and the NERC Functional Model.** LSEs do not have the ability to ensure the implementation of the schedule adjustments required in the existing FERC-approved IRO-STD-006-0 Standard.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

5. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

PRC-004-WECC-1 — PROTECTION SYSTEM AND REMEDIAL ACTION SCHEME MISOPERATION

NERC COMMENT:

5. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

WECC RESPONSE:

1. WECC recognizes that the standard drafting team included explanatory text in the requirement section in an attempt to clarify the requirements. However, the duplication does not adversely impact the applicability, clarity, or the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

6. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

WECC RESPONSE:

2. WECC recognizes that the standard drafting team included System Operators and System Protection personnel in the requirements. R1. of PRC-004-WECC-1 states that, **"System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection Systems and RAS operations."** As written the requirement is sufficiently clear and well-defined to be enforceable on the entities in the Western Interconnection. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

7. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

WECC RESPONSE:

3. WECC recognizes that the standard drafting team included explanatory text in the requirement section that might be more appropriately included as a footnote. However, the text clarifies the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

8. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

WECC RESPONSE:

4. The requirements in the PRC-004-WECC-1 Standard are clearly written. Industry stakeholders did not submit any comments questioning the clarity of the standard. The alternative standard drafting formats or language used in this standard, are applicable exclusively to the Western Interconnection. These stylistic differences do not affect others and should not be a consideration for NERC approval.

<u>TOP-007-WECC-1 — SYSTEM OPERATING LIMITS (SOLs)</u>

NERC COMMENT:

3. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

WECC RESPONSE:

1. In the Western Interconnection, SOLs are designed so that during steady-state operations, with all lines in service, the system is at least two contingencies away from cascading. Therefore, exceeding an SOL for the 40 major paths identified in the TOP-007-WECC-1 Standard would not typically qualify as an Interconnection Reliability Operating Limit (IROL) under NERC's TOP-007-0 Standard. The standard drafting team created the TOP-007-WECC-1 Standard to limit the amount of time that a SOL may be exceeded for these very important paths, which makes the TOP-007-WECC-1 Standard more stringent than the NERC standard.

NERC COMMENT:

4. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

WECC RESPONSE:

2. The existing standard created confusion during system operation because system conditions may change the limiting conditions on a path. This is because the limit depends upon whether thermal, stability, or post transient limitations are the limiting factor. In addition, having different response times for paths (and sometimes for the same path depending on current outage conditions), complicates system operation, causing delays in responding to the path overload. This resulted in path operators implementing more drastic actions to respond to a contingency within 20 minutes, which may put the system at greater risk, particularly during heavy load periods such as summer. The standard drafting team determined that changing the standard from a 20-minute to a 30-minute response time is insignificant in terms of the probability of a next contingency occurring. Moreover, the drafting team believes that following a system disturbance, the system operators will be better able to identify what generation to ramp in order to be effective in mitigating the overload. This will also allow them to coordinate with others before implementing the generation ramps. Therefore, the simplification of the standard to one consistent 30-minute period improves reliability. It is important to recognize that in spite of extending the recovery period, the refinement should improve system reliability.

VAR-002-WECC-1 — AUTOMATIC VOLTAGE REGULATORS (AVRs)

NERC COMMENT:

4. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-002-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002a-1 Standard. The 98 percent in Requirement R1. of VAR-002-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-

STD-002a-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring the AVR to be in service provides for time to start up generating facilities. It also allows for evaluation when the Generator Operators respond to unforeseen events.

NERC COMMENT (continued):
More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

WECC RESPONSE (continued):
NERC VAR-002-1a R1. permits the Generator Operator to operate in different modes by simply notifying the Transmission Operator. There are no restrictions on the length of time or reasons for operating in other modes. The WECC 1996 outage reports identified the lack of reactive support from generators with AVRs operating in modes other than voltage control as one of the causes of the WECC 1996 outages. The VAR-002-WECC-1 Standard limits the reasons and time for operating a generator without the AVR in service and controlling voltage, therefore it is more stringent than the NERC VAR-002-1a Standard.

NERC COMMENT

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the AVR in service). The use of peaking units adds to overall system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>VAR-501-WECC-1 — POWER SYSTEM STABILIZER (PSS)</u>
NERC COMMENT:

4. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in

Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-501-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002b-1 Standard. The 98 percent in Requirement R1. of VAR-501-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002b-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring PSS to be in service provides time for evaluation and to start up generating facilities when Generator Operators respond to unforeseen events.

NERC COMMENT:

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the exiting standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the PSS in-service). Operating at low megawatt levels makes the PSS ineffective. The use of peaking units adds to over-all system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture PSS in service recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes that the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

(NERC) CONCLUSION

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC RESPONSE

WECC appreciates the opportunity to discuss NERC staff's initial evaluation and report in conference calls on August 4 and 5, 2008 and to provide the written clarifications and responses contained herein. We trust that WECC's responses, along with all the supporting documentation contained in WECC's submissions, provide the NERC staff a comprehensive basis for recommending NERC Board of Trustees approval of all proposed standards. Please direct any questions relating to WECC's response to WECC Director of Standards, Steve Rueckert at steve@wecc.biz or (801) 883-6878.

WECC Responses to FERC Staff Concerns and Questions
Regarding the Proposed WECC Tier 1 Standards
June 17, 2008

I. Contingency Reserves – BAL-002-WECC-1

A. Period of Contingency Reserve Restoration: Does the proposed standard modify the current standard to provide a longer period of time of 90 minutes rather than 60 minutes?

Yes, the requirement to restore contingency reserves within 60 minutes was eliminated in the proposed standard. The current standard requires the restoration of contingency reserves within the first 60 minutes following an event. By eliminating this requirement in the proposed standard, WECC adopts the NERC default standard that requires the restoration of contingency reserves within 90 minutes from the end of the disturbance recovery period.[2]

The 60 minute restoration period required by the current standard was developed and used under a manual interchange transaction structure among vertically integrated utilities. As the electric utility industry restructured, there has been a substantial increase in the number of market participants and interchange transactions.[3] To accommodate the increase in number of interchange transactions and market participants an electronic tagging system was implemented in the Western Interconnection. The adoption of an electronic tagging system that accommodates multiple market participants and a large number of interchange transactions made the current mid-hour reserve restoration more cumbersome and made the inappropriate rejection of reserve restoration transactions more likely because such transactions are outside the electronic tagging cycle.

Eliminating the 60 minute reserve restoration requirement and adopting the NERC requirements results in more efficient communication among Balancing Authorities (BAs) because it aligns the restoration of contingency reserves with the electronic tagging system approval cycle. Adopting the NERC contingency reserve restoration requirements reduces the potential for reserve transactions being inappropriately rejected resulting in improved communication among BAs resulting in improved reliability.

B. Shedding of Firm Load: Does the proposed standard change the treatment of the shedding of firm load compared to the current standard?

No, both standards allow for the shedding of firm load under limited circumstances. The addition of requirement R3.4 in the proposed standard clarified the process. During capacity and energy emergencies, a BA or Reserve Sharing Group (RSG) may use load as non-spinning reserves; that is BAs and RSGs will not drop load to maintain their non-spinning reserve requirement. Rather they will use load as part of their non-spinning contingency reserves.

[2] See NERC Standard BAL-002-0 Requirement R6 and WECC Standard BAL-STD-002-0 WR1.d.
[3] Balancing Authorities in the Western Interconnection approve between 2,500 and 4,500 interchange transactions per day.

This standard emphasizes the responsibility of serving customer load first while at the same time protecting the reliability of the Western Interconnection. Even during capacity and energy emergencies, BAs and RSGs are required to comply with the spinning reserve requirements.

C. Deliverability of Contingency Reserves: Does the proposed standard require that contingency reserves be deliverable?

Yes, nothing has changed with respect to the deliverability of contingency reserves.

D. Interruptible Imports: In the current standard the sink BA is required to carry an additional amount of contingency reserves equal to the amount of interruptible imports. Does the proposed standard have the same requirement?

Yes, the term interruptible imports was eliminated from the proposed standard. It was replaced with the added requirement R1.2 which requires that "If the Source BA designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink BA shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s)." This is an improvement from the current standard because it eliminates ambiguity in the term interruptible imports.

E. Demand Side Management: Did the drafting team comply with FERC Order 693 to explicitly allow demand-side management (DSM) to be used for reserves?

Yes, DSM that is deployable within 10 minutes is a subset of interruptible load. Interruptible load is defined in requirement R3.2 as an acceptable type of contingency reserve.

II. Qualified Transfer Path Unscheduled Flow Relief- IRO-006-WECC-1

A. Is the proposed standard intended to address an actual (real time) overload situation?

No, a different standard TOP-007-WECC-1 covers actual (real time) overload situations. The proposed IRO-006-WECC-1 standard includes requirements to reduce schedules, which requires adjustments to generation patterns, to prevent potential overloads during the next operating hour.

B. Should the Unscheduled Flow Mitigation Plan (UFMP) be incorporated in the IRO-006-WECC-1 by reference?

No, the key reliability portions from the UFMP are incorporated in the proposed standard. It is not necessary to reference the remainder of the UFMP.

C. Does the WECC UFMP need to be updated?

Yes, WECC has initiated the process of updating its UFMP.

III. System Operating Limits—TOP-007-WECC-1

A. Could the language in TOP-007-WECC-1 allow for the system to be less than two contingencies away from cascading and more specifically one contingency away from cascading?

No, the proposed standard is designed such that path operations must be at least two contingencies away from cascading during steady state operations. In real time operations when System Operating Limits (SOL) are exceeded for periods not to exceed 30 minutes, there may be system conditions that are less than two contingencies away from cascading.

B. Could IRO-005-2 Requirements R3 and R5 be interpreted that the power system is being operated two contingencies away from a cascading outage while WECC TOP-007-WECC-1 requirement R1 results in the power system being operated one contingency away from a cascading outage?

No, IRO-005-2 requirements R3 and R5 are consistent with the requirements in TOP-007-WECC-1. In the Western Interconnection SOLs are developed in such a manner that the system operation is at least two contingencies away from a cascading failure. This is implicit in the identification of the SOL derivation. If, however, there is a flow that exceeds the SOL, Transmission Operators (TOP) and Reliability Coordinators (RC) must take proactive immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the transmission path exceed the SOL for more than 30 minutes, thus protecting the system from potential cascading for a subsequent contingency.

C. Do SOL changes within the hour extend the time for compliance?

No, SOL changes within an operating hour do not extend the time for compliance.

IV. Automatic Voltage Regulators and Power System Stabilizers – VAR-002-WECC-1 and VAR-501-WECC-1

A. How does VAR-002-WECC-1 coordinate with the new NERC Standard VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules?

VAR-002-WECC-1 contains specific, more restrictive, requirements on generator operators regarding the operation of Automatic Voltage Regulators (AVR) that are not contained in the NERC Standard VAR-002-1. The reasons for these more restrictive requirements are to support transfer capabilities in the Western Interconnection and to address the insufficient supply of reactive power identified as a cause of the 1996 system disturbances in the Western Interconnection. The drafting team designed the VAR-002-WECC-1 Standard to limit the reasons for operating AVRs in a mode that does not control voltage and the amount of time permitted for such operations. Generator operators are still required to comply with all the requirements contained in NERC VAR-002-1.

B. Are Power System Stabilizers (PSS) included in either of these standards?

Yes, VAR-501-WECC-1 contains requirements regarding the in-service operation of PSS.

C. Why were the AVR and PSS replacement period extended to two years from 15 months?

The amount of time to replace AVR and PSS was lengthened to accommodate the approval and procurement time frames for AVR and PSS for nuclear power plants, which are two years.

V. Transmission Maintenance – FAC-501-WECC-1

A. Does the FAC-501-WECC-1 standard reduce the number of lines that are subject to this standard to the SOL limiting factors from the lines and facilities associated with the 40 paths thereby reducing the obligation for maintenance?

No, there is no change in the number of lines or facilities subject to the proposed FAC-501-WECC-1 standard.

PRC-005-WECC-1 — Transmission Maintenance — Response to Comments
October 23, 2007

Thank you for the opportunity to review the proposed regional standard. I have just a couple of comments.

I think the standard ought to be an FAC (Facilities Design, Connections and Maintenance) standard rather than PRC (Protection and Control) since it deals exclusively with facilities and not with protection and control.

Reply: The drafting team changed the name of the standard from PRC-005-WECC-1 to FAC-501-WECC-1 to better align with the NERC numbering system.

I think the phrase "although they are not as prevalent as protective relay failures and vegetation related problems" is unnecessary and ought to be eliminated from the "Justification for a Regional Standard."

Reply: The drafting team removed the phrase "although they are not as prevalent as protective relay failures and vegetation related problems."

R1.1 - Annual review of the TMIP seems excessive but I would leave that contention to the people that will be developing and maintaining the TMIP. (The Time Horizon is indicated as Long-term Planning, however).

Reply: The drafting team believes the process for "Annual Review" should continue. The requirement does not require that an entity to change its TMIP each year. It requires that entities verify annually that they are following the plan.

Thank you for the opportunity to comment.

Bill Middaugh
TriState Generation and Transmission Association, Inc.

Justification for a Regional Standard: (PER-005-1) should be (PRC-005-1)

Reply: This was a typo and was corrected.

R1.1, M1.1 and 2.1.1: TMIP should be reviewed every five years, rather than annually.

Reply: The drafting team believes the process for "Annual Review" should continue. The requirement does not require that an entity to change its TMIP each year. It requires that entities verify annually that they are following the plan.

Roberto Rojas
Tri-State G&T
Transmission Maint. Mgr.-East

The standard does not allow for any deviation from the annual plan if certain pieces of TMIP equipment could not be taken out of service for unforeseen circumstances.

Reply: Entities need to address maintenance for each of the items required. Entities may include in the TMIP the flexibility for unforeseen circumstances.

From a station maintenance point of view, what is meant by "Contamination Control" on Page 9, 4b?

Reply: Contamination Control would be any effort to monitor and control contaminates that degrade insulation on substation equipment.

On Page 9-4c, there is no reference to relaying or communications equipment which we currently include in the TMIP plans. Would the communications equipment be removed from future TMIP plans if this standard is approved (as worded)?

Reply: NERC has standards covering maintenance for relay and communication equipment. This standard does not require relay and communication equipment to be included in the TMIP.

Minor detail, but page numbering goes from "Page 7 of 12" to "Page 8 of 9".

Reply: This was corrected.

Gary Snyder
PNM

A broad definition of the "associated facilities" addressed by a TMIP might include end to end hardware, software, and vegetation related to the specific transmission line. Since protective relays are the focus of PRC-005-1, the associated facilities should be defined using specific categories such as those used in PRC-017-0 Requirement 1.1. This type of definition would delineate PRC-005-1 from the FAC group of standards. Transmission line maintenance may be better served in FAC-003-1.

Nick Lewis

Reply: The Transmission Operators define the "associated facilities" necessary to maintain SOLs for the paths. The drafting team changed the name of the standard from PRC-005-WECC-1 to FAC-501-WECC-1 to better align with the NERC numbering system and to differentiate from the relay maintenance standards.

The applicability of this standard resides on the Transmission Owners and should not be the responsibility of the Transmission Operators. The Functional Model descriptions of the each of these entities provide that the owner is responsible for equipment and transfers the responsibility to the Operator through agreements. Functional Model Reference: Transmission Owner #9 and Transmission Operator #2 and #15 (See Below).

From Functional Model:

Responsible Entity – Transmission Operator

Relationships with Other Responsible Entities

2. Receives maintenance requirements and construction plans and schedules from the Transmission Owner and Generation Owner

15. Develops operating agreements or procedures with Transmission Owners.

Responsible Entity – Transmission Owner

Relationships with Other Responsible Entities

9. Provides maintenance plans and schedules to the transmission Operator and Transmission Planner.

Reply: References to Transmission operator were removed to align with the functional model and NERC.

Also, this standard should be renumbered as it no long has any connection with Protection or Control equipment and only provides for the maintenance of major equipment. I would suggest maybe a FAC (Facilities Design, Connections, and Maintenance) or TOP (Transmission Operations). The current PRC-005 and others PRC standards cover relay maintenance.

Reply: The drafting team changed the name of the standard from PRC-005-WECC-1 to FAC-501-WECC-1 to better align with the NERC numbering system.

Jonathan Sykes
Salt River Project

Applicability
A review of the NERC Reliability Functional Model, Version 3 shows that responsibility for transmission maintenance rests with the Transmission Owner (TO).

“The Transmission Owner owns and maintains its transmission facilities.”

“The Transmission Operator operates or directs the operation of transmission facilities, and is responsible for maintaining local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility.”

The Functional Model expands on the topic in this standard further:

“The Transmission Operator may also physically provide or arrange for transmission maintenance, but it does this under the direction of the Transmission Owner, who is ultimately responsible for maintaining its transmission facilities.”

The Functional model is clear on this. The Transmission Owner is the responsible entity for maintenance. If a TOP provides for this service, it is through agreements/delegation from the TO.

We recommend removing Transmission Operator from the Applicability, Requirements, Measures, and Compliance sections to ensure compatibility with the commonly understood NERC responsible entity.

Reply: References to Transmission Operator were removed to align with the functional model and NERC.

The terms “transmission facilities” and “associated facilities” are not clear and should be better defined. For example, are “associated facilities” that equipment that may not be part the path, but located at a substation adjacent to the path, where a relay failure would open the path via backup relaying?

Reply: The Transmission Operators define the “associated facilities” necessary to maintain SOLs for the paths. NERC defines facilities.

We think that R.4. is actually a measure of R.3. We recommend that R.4. be deleted and that M.4. be combined with M.3. to read as follows:

M3. Transmission Owners shall have evidence that they implemented and followed their TMIP. Transmission Owners shall have maintenance and inspection records that support the TMIP in accordance with R.3. The records could include, but is not limited to:
1. The crew responsible for performing the work or inspection,
2. The date(s) the work or inspection was performed,
3. The transmission facility on which the work was performed, and
4. A description of the inspection or maintenance performed.

This change would also require changes to the following :

Section 1.3 Data Retention
Section 2.1.4 Violation Security Levels
Attachment 2

Reply: The drafting team removed R4 and made necessary refinements.

• In Attachment 2, need to add the spirit of bullets 3, 4, 5, and 6 for the existing standard section B.b.i. (a). (see below). This should include describing the maintenance method for each activity along with the basis for using the maintenance triggers. Specify the condition assessment. Without this detail, the TMIP is just a list of activities with no basis.

• Describe the maintenance, testing and inspection methods for each activity or component listed under Transmission line Maintenance and Station Maintenance;

Reply: Maintenance and testing activities are covered with Attachment 2-FAC-501-WECC-1 item 2. Additional details explaining how to comply with standard should not be part of a standard.

• Provide any checklists or forms, or reports used for maintenance activities;

Reply: The measurement section covers the items to be provided for an audit. All other reporting requirements will be handled by the compliance monitor.

• Provide criteria to be used to assess the condition of a transmission facility;
Specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the transmission facilities.

Reply: This issue is covered in the measurement section. Additional details explaining how to comply with standard should not be part of a standard.

Charles Cumpton
CAISO

Thanks for the opportunity to comment on behalf of Nevada Power Company and Sierra Pacific Power Company.

I agree with previous comments that this revised Regional Standard no longer has pertinence in the NERC “PRC” category, and rather should be numbered in the “FAC” area of the Standards to avoid confusion.

Reply: The drafting team changed the name of the standard from PRC-005-WECC-1 to FAC-501-WECC-1 to better align with the NERC numbering system.

I suggest an increase in the review period for an entity’s TMIP from the proposed 1-year to a minimum of 3 years, perhaps with a provision that it must be updated as additional facilities become applicable to an entity; ie, a new line being placed in service and added to the table of WECC Paths in this Standard. I believe that one year is far to frequent for such a review and will yield little, if any value.

Reply: The drafting team believes the process for “Annual Review” should continue. The requirement does not require that an entity to change its TMIP each year. It requires that entities verify annually that they are following the plan.

Similar to the remarks of a previous commenter, I believe that R3 and R4 are really getting at the same thing: The entity must implement and follow its TMIP. The “proof” should be in the measure of R3, not as a separate requirement R4. I recommend elimination of R4, and merging of M3/M4.

Reply: The drafting team removed R4 and made necessary refinements.

Att 2 Maintenance Details
I would suggest elimination of “Contamination Control” as a specific point in the Station Maintenance Details and in Transmission Line Maintenance Details. The general condition of station equipment insulation and line insulation is a component of any prudent inspection activity for a these facilities, and we see no reason to single out this one particular area of inspection without specifying all of the other things that should receive similar attention.

Reply: Contamination Control efforts may be more critical in some locations within the region. Contamination Control would be any effort to monitor and control contaminates that degrade insulation on substation equipment.

Violation Severity Levels
My general sense of these VSL’s is that there is much subjectivity as to the degree of violation. For example, if I’ve got 1,000 structures to inspect on a given transmission line, and I only get to 999 of them, have I “implemented and followed” my TMIP? Also, there may be valid reasons for not being able to complete the activities specified in the TMIP, such as inability due to system loading/configuration to take equipment out of service. It may be less risky to forego a maintenance item specified in the TMIP than to subject the grid to the risk of removing the equipment from service. We are faced with these sorts of decisions all the time.

Reply: Entities need to address maintenance for each of the items required. Entities may include in the TMIP the flexibility for unforeseen circumstances.

For VSL 2.1.4, how would one have evidence of implementation and following the TMIP if he didn’t have the maintenance and inspection records? I don't understand how this would be applied

Reply: Refinements were made to the violation severity levels.

It appears that VSL 2.1.2 should refer to R1, not R2, and VSL 2.1.3 should refer to R2, not R3.

Reply: The drafting team corrected this issue.

Thanks for the opportunity to comment. I appreciate the work of the Drafting Team.

Rich Salgo
Sierra Pacific Resources Transmission

One other comment regarding applicability of this Standard: With regard to the Attachment 1, Existing WECC Transfer Paths of Bulk Electric System, I question how it is determined that a particular Path gets placed on this list, and how a Path might be removed if it is known to be relatively insignificant. What process exists or will exist to review and assess which lines should and should not be on the list, and what criteria apply? Of particular concern to me is the continued inclusion of the SPPC-PG&E Path #24, consisting of a pair of 115kV lines and one 60kV line with a rating of barely 100MW in one direction and as little as 10MW in the other. The prominence of this Path and its importance to the Interconnection doesn’t even compare to the other facilities that grace this list, such as EOR and COI. In fact, as a testimonial to this Path’s insignificance, the phase shifter that fully controls Path 24 was recently disqualified by UFAS as a Qualified Device for unscheduled flow mitigation because of the negligible effect the Cal Sub PST’s have today on the

WECC Qualified Transfer Paths. While this may not be within the expected scope of the Drafting Team, it does go to the applicability of this Standard and therefore is important to resolve.

Reply: The inclusion of the path is outside of the scope of this drafting team.

Rich Salgo
Sierra Pacific Resources Transmission

In general, standard PRC-005-WECC-1 deals with maintenance of transmission lines and substation facilities including relaying for specific paths identified in Attachment 1, whereas NERC standard PRC-005-1 deals only with relaying and associated relaying equipment for all transmission facilities 100kV and above. This is somewhat confusing as PRC standards deal with various aspects of relaying systems. Others have commented on this issue and recommend that this standard be reclassified as a facility standard FAC. I think I would agree.

PRC-005-WECC-1 implies that the transmission owner shall have, maintain and document a transmission maintenance and inspection program for all facilities in Attachment 1. This should only apply to the lines and termination equipment owned and maintained by the transmission owner. In the case where two transmission owners own and maintain a common transmission facility or path. Each transmission owner should develop, maintain and document a TMIP for that portion of the path of which they own.

Reply: The Transmission Operators define the "associated facilities" necessary to maintain SOLs for the paths. The drafting team changed the name of the standard from PRC-005-WECC-1 to FAC-501-WECC-1 to better align with the NERC numbering system and to differentiate from the relay maintenance standards. Yes, each transmission owner should develop, maintain, and document a TMIP for that portion of the path of which they own.

Requirement R.1 states that Transmission Owners and Transmission Operators shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operations Limits associated with each of the transmission paths identified in Attachment 1. Our interpretation of this requirement is that it applies to the path identified in Attachment 1 and associated termination equipment alone. If other transmission facilities not listed in Attachment 1 have potential impacts on the SOL of the path listed in Attachment 1 these facilities are not covered by the standard.

Reply: The Transmission Operators define the "associated facilities" necessary to maintain SOLs for the paths. These transmission facilities are covered by the standard.

Requirement R1.1 and Measurement M1.1 require annual review and documentation of the TMIP and updating as needed. This I believe is excessive and would have little value. Many maintenance activities can be longer than a year and some extensive maintenance activities may be many years between maintenance intervals. This evaluation and documentation should be extended to say a 5 year interval.

Reply: The drafting team believes the process for "Annual Review" should continue. The requirement does not require that an entity change its TMIP each year and perform annually all maintenance. It requires that entities verify annually that they are following the plan.

Frank Johnson
Substation Construction & Maintenance Manager
SDG&E

The FAC-501-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the WECC FAC-501-WECC-1 Standard. This Standard was posted for a 30-day public comment period from November 9, 2007 through December 10, 2007. The Standard Drafting Team asked stakeholders to provide feedback on the standard through posting it comment on the WECC website. There were four sets of comments from four companies.

In this ‘Consideration of Comments’ document, stakeholder comments have been organized so that it is easier to see the responses associated with each comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Steve Rueckert at 801-582-0353 or at steve@wecc.biz. In addition, there is a WECC Appeals Process.

Comments and Responses

There should be a requirement to provide the evidence upon request by WECC or NERC. This will be further incentive for each owner to keep up-to-date records and give WECC and NERC the ability to request this data. Maybe:

R.4. The Transmission Owner shall provide to WECC and NERC within 30 days of the request documentation of its TMIP and provide evidence that they are meeting the TMIP.

The Violation Se[verity] Levels should contain penalties for the following violations:

Lower: Incomplete o[r] lack of evidence provided to WECC or NERC.

Moderate: Owners are one month late in performing their TMIP.

High: Owners are two months late in performing their TMIP.

Severe: Owners are 4 months late in performing their TMIP.

In some instances, the owner may be making ever[y] effort to meet the standard, but may be late in performing the maintenance or inspections. The violation factors based on how much the owner is late in performing their TMIP will provide incentive to stay on track with the TMIP cycles and make the Western Interconnection more reliable.

Thanks
Jonathan Sykes
Salt River Project

Reply: This recommendation is a measurement for a time based maintenance practice and does not work well with performance-based maintenance activities. The drafting team believes the 30-day requirement to provide information is already built into the compliance submission requirements and is not needed in the standard.

California ISO

The CAISO appreciates the drafting team being receptive to our comments on the original posting. We would suggest the following to further enhance this standard:
For attachment 1, Section 2, we suggest that this section is rewritten to state, "Describe each TMIP activity along with its basis and the analysis of what triggers each activity."

Thank you for your effort on the revisions of this standard.

Brent Kingsford
California ISO

Reply: Thank you for your comment. Adding the basis and analysis for a maintenance standard is ideal but is beyond the scope of this standard and would be difficult to measure. The intent of this standard is to verify that maintenance is planned and performed in accordance with a TMIP.

The Alberta Electric System Operator appreciates the opportunity to comment on the standard under development.

We would like to see the term "Compliance Enforcement Authority," in section D 1.1, defined within the standard. The acronym used in D 1.1 (CEA) is defined on the WECC website in the Glossary/Acronyms link as the Canadian Electricity Association.

Pending clarification of the term noted above the AESO has no concerns on the requirements but would like to emphasize that although Path 1 is included in the list, the standard is not enforceable in Alberta until it has received Regulatory Approval here.

Mark Thompson
AESO

Reply: Thank you for your comment. This standard is not enforceable in Canada until provincial Canadian regulatory authorities have approved the standard. NERC recommended use of the term Compliance Enforcement Authority (CEA) in continent wide and regional standards. Resolving the conflict between acronyms is beyond the authority of this drafting team.

This version has many improvements, so thank you to the team for their efforts.

One additional item that we would like to see either in the Purpose or in Attachment 1, under 4. Station Maintenance Details, please add a comment that notes a specific exclusion for protective relays, controls and associated communication system. These devices are covered under NERC PRC-005.

Reply: The drafting team modified the standard number from PRC-005-WECC-1 to FAC-501-WECC-1 to eliminate the correlation with protective relaying, controls, and associated communication systems. Therefore, the drafting team believes this recommendation has been accommodated.

In addition, there is an editorial for M3.1., please add "The person or crew..."

Reply: The drafting team implemented this recommendation.

Thank you
Kris Buchholz
PG&E

Drafting Team FAC-501-WECC-01

FIRST NAME	LAST NAME	COMPANY
John	Bocka	Southern California Edison Company
Donald	Bryce	DOI - Bureau of Reclamation
Jay	Campbell	Sierra Pacific Resources Transmission
Edward	Hulls	Western Area Power Administration (WACM)
Mike	Gugerty	Southern California Edision
David	James	Avista Corp.
Ken	Wilson	WECC
Greg	Lange	Public Utility District No. 2 of Grant County
David	Neumayer	Western Area Power Administration
Paul	Rice	Western Electricity Coordinating Council
Kevin	Pera	Public Service Company of Colorado
Glenn	Rounds	Pacific Gas and Electric Company
Randy	Spacek	Avista Corporation
Robert	Temple	RDRC
Mark	Willis	Sacramento Municipal Utility District

Appendix 9

OPERATING COMMITTEE

FAC-501-WECC-1

SP - State and Provincial | IS - Interested Stakeholder
TP - Transmission Provider
TC - Transmission Customer

Name of Organization	Name of Voting Member	Voting Class	YES	NO	Abstain
Alberta Electric System Operator (AESO)	Doug Hincks	TP	X		
AltaLink L.P. (ALTA)	Rick Spyker	TP	X		
Aquila Networks-WPC (WPE)	Al Logan	TC			X
Arizona Public Service (AZPS)	Mark Hackney (alternate)	TP	X		
Arizona Public Service (AZPS)	David Hansen	TC	X		
ATCO Electric Ltd. (ATCO)	Blaine Beisiegel	TP	X		
Avista Corp	Scott J. Kinney (alternate)	TP	X		
Basin Electric Power Cooperative (BEPC)	Becky Kern	TC			X
Bear Energy LP (BEAR)	Jeff Winkler (alternate)	TC	X		
Black Hills Power and Light Company (BHPL)	Pam Pahls	TP	X		
Bonneville Power Administration-Power Bus Line (BPAP)	Fran Halpin	TC	X		
Bonneville Power Administration-TBL (BPAT)	Don Watkins	TP	X		
British Columbia Hydro and Power Authority (BCHA)	Clement Ma	TC	X		
British Columbia Transmission Corporation (BCTC)	Devinder Ghangass	TP	X		
California Department of Water Resources (CDWR)	Glenn Solbert	TC	X		
California Energy Commission (CEC)	Bill Chamberlain (alternate)	SP	X		
California ISO (CISO)	James McIntosh	TP	X		
California Mexico Reliability Center	Greg Tillitson - TC	IS	X		
Calpine Corporation (CALP)	Frank Obertance	TC			X
Colorado Springs Utilities (CSU)	Steve Schaarschmidt	TP			X
Coral Power LLC	Michael Wong	TC	X		
Deseret Generation & Transmission Co-op (DGT)	Phil Tice	TC	X		
Deseret Generation & Transmission Co-op (DGT)	L'Dee Curtis	TP	X		
Dynegy, Inc. (DYN)	Brian Theaker	TC	X		
El Paso Electric Company (EPE)	Jose Nevarez	TP			X
Eugene Water & Electric Board (EWEB)	Dean Ahlsten	TC	X		
Fortis Energy Marketing & Trading Group (FEMT)	Jay Alexander	TC			X
Gila River Power, L.P. (PGR)	Kenneth Parker	TC			X
Highland Energy LLC	Bryan Bradshow	IS			X
Idaho Power Company (IPC)	Tessia Park	TP	X		
Idaho Power Company (IPC)	Shaun Jensen	TC			X
Metropolitan Water District of Southern California (MWD)	Garry Chinn	TP	X		
Mirant Americas, Inc. (MIR)	John Stout	TC	X		
Modesto Irrigation District (MID)	Toxie Burriss	TP		X	
Morgan Stanley Capital Group Inc.	Patrick Murray (alternate)	TC	X		
Northern California Power Agency (NCPA)	Fred Young	TC			X
NorthWestern Energy (NWMT)	Mark Donaldson (alternate)	TP	X		
NRG Power Marketing, Inc. (NRG)	Robert Bailey	TC	X		
Pacific Gas & Electric (PG&E)	Kris Bucholz	TP	X		
Pacific Gas & Electric (PG&E)	Joe Minkstein	TC	X		
PacifiCorp (PACM)	John Apperson	TC	X		
PacifiCorp (PAC)	Robert Williams	TP	X		
Platte River Power Authority (PRPA)	John R. Powell	TP	X		
Portland General Electric (PGE)	Mike Ryan	TP	X		
Portland General Electric (PGE)	John Jamieson (alternate)	TC			X
Powerex (PWX)	Mike Goodenough	TC	X		
PPL EnergyPlus, LLC (PPLE)	John Cummings (Alternate)	TC	X		
PPM Energy, Inc. (PPM)	Diana Scholtes (alternate)	TC			X
Public Service Company of Colorado (PSC)	Robert Johnson	TP	X		
Public Service Company of Colorado (PSC)	Steve Buening	TC	X		
Public Service Company of New Mexico (PNM)	Keith Nix	TP	X		
Public Service Company of New Mexico (PNM)	David Miller	TC			X
Public Utility District No. 1 of Chelan County (CHPD)	Hugh Owen	TC	X		
Public Utility District No. 1 of Douglas County (DOPD)	Henry E. (Hank) LuBean	TP	X		
Public Utility District No. 2 of Grant County (GCPD)	Greg Lange	TC	X		
Puget Sound Energy, Inc. (PSE)	Gary Nolan (alternate)	TP	X		
Puget Sound Energy, Inc. (PSE)	Joe Hoerner (alternate)	TC			X
Reliant Energy, Inc. (REI)	Thomas J. Bradish	TC			X
Sacramento Municipal Utility District (SMUD)	Vicken Kasarjian	TC		X	
Salt River Project (SRP)	Mike Hummel	TC	X		
San Diego Gas & Electric Company (SDGE)	Scott Peterson	TP		X	
Seattle City Light (SCL)	Pawel Krupa	TC	X		
Sempra Generation (SER)	Leslie Padilla	TC	X		
Sierra Pacific Resources Transmission (SPR)	Rich Salgo	TP	X		
Sierra Pacific Resources Transmission (SPR)	Sheryl Torrey	TC	X		
Southern California Edison Company (SCE)	Thomas J. Botello	TP	X		
Southern California Edison Company (SCE)	John Pespisa	TC	X		
Southwest Transmission Cooperative, Inc. (SWTC)	Shane Sanders	TP	X		
SUEZ Energy Marketing NA, Inc. (SUEZ)	Caitlan Collins	TC	X		
Tacoma Power (TPWR)	Catherine Leone-Woods	TC	X		
Transmission Agency of Northern California (TANC)	John Forman	TP		X	
Tri-State Generation & Transmission Association, Inc (TSGT)	Thomas A. Smith	TP	X		
Tucson Electric Power Company (TEP)	John Tolo	TP	X		
Turlock Irrigation District (TID)	Casey Hashimoto	TP		X	
U.S. Army Corps of Engineers	Karl Bryan	IS	X		
U.S. Bureau of Reclamation (USBR)	Deon Murphy	TC	X		
Utah Municipal Power Agency (UMPA)	Layne Burningham	TP	X		
Utility System Efficiencies, Inc.	LeRoy Patterson	TC			X
Western Area Power Administration (WAPA)	Edwad Hulls	TP	X		
Western Area Power Administration (WAPA)	Ken Otto	TC	X		
	Voting Summary	Class	Yes	No	Abstain
		SP	1	0	0
		TC	30	1	14
		TP	28	4	2
	total		59	5	16

Board of Directors			
April 16-18, 2008		Voting Summary	
Coronado, CA		FAC-501-WECC-1	
Last Name	**First Nar**	**Organization**	**Class**
Anderson	Bob	Non-affiliated Director	Non-Affiliated
Areghini	David	Salt River Project	Class 1
Barbash	Carolyn	Sierra Pacific Power Company	Class 1
Beyer	Lee	California Public Utilities Commission	Class 5
Brown	Duncan	Calpine Corporation	Class 3
Campbell	Ric	Utah Public Service Commission	Class 5
Cauchois	Scott	CADRA	Class 4
Chamberlain	Bill	California Energy Commission	Class 5
Cleary	Anne	Mirant Americas, Inc.	Class 3
Conway	Teresa	Powerex Corp.	Class 6
Coughlin	John	Non-affiliated Board Member	Non-Affiliated
Dearing	Bill	Grant County PUD	Class 2
Ferreira	Richard	TANC Executive Advisor	Class 2
Grantham-Richards	Maude	Farmington Electric Utility System	Class 2
Gutting	Scott	Energy Strategies, LLC	Class 4
Kelly	Nancy	Utah Committee of Consumer Services	Class 4
King	Jack	Non-affiliated Board Member	Non-Affiliated
LaFond	Steve	The Boeing Company	Class 4
Little	Doug	British Columbia Transmission Corporation	Class 6
McMaster	Dale	Alberta Electrical System Operator	Class 6
Moya	Jesus	Comision Federal de Electricidad	Mexico
Newton	Tim	Non-affiliated Director	Non-Affiliated
Sharpless	Jananne	Non Affiliated Board Member	Non-Affiliated
Smith	Marsha	Idaho Public Utilities Commission	Class 5
Stout	John	Mariner Consulting	Class 3
Tarplee	Gary	Southern California Edison	Class 1
Thuston	Tim	Williams Power	Class 3
Weis	Larry	Turlock Irrigation District	Class 2
VanZandt	Vicki	Bonneville Power Administration	Class 1
Zaozirny	Lori Ann	British Columbia Utilities Commission	Class 6
The Board Members listed above voted whether to approve FAC-501-WECC-1.			
The Regional Reliability Standard was approved unanimiously.			

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

Action: PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation — **Approve**

Proposed Effective Date: On the first day of the second quarter, after applicable regulatory approval.

Summary Conclusion and Recommendation:

- NERC recommends approval of PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation and four associated definitions on the basis that the Regional Reliability Standard is more stringent than the corresponding NERC Reliability Standard, PRC-004-1 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations, thus satisfying the statutory criteria for a Regional Reliability Standard.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

Background*:* FERC approved Regional Reliability Standard WECC-PRC-STD-001-1 — Certification of Protective Relay Applications and Settings on the basis it is more stringent than the continent-wide NERC Reliability Standard PRC-001-1 — System Protection Coordination. Specifically, the WECC Regional Reliability Standard requires that transmission owners and transmission operators analyze and certify all relay settings and operations on specified paths to determine whether operations were correct, and that current information on relays is provided to the transmission operators. WECC explains that it goes beyond the related NERC Reliability Standard by requiring certification that all relay settings and operations on specified transmission paths are appropriate. The certification requirement provides an additional level of assurance that protection systems will operate as they should in order to provide for interconnection reliability.

FERC also approved Regional Reliability Standard WECC-PRC-STD-003-1 — Protective Relay and Remedial Action Scheme Misoperation on the basis it is more stringent than the continent-wide NERC Reliability Standard PRC-003-1 — Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems. Specifically, PRC-003-1 requires the analysis of misoperations within 90 days and the submission of corrective action plans. The WECC Regional Reliability Standard goes further by requiring equipment that has misoperated be removed within 22 hours and; requires repair or replacement of equipment that has misoperated within 20 business days for the specific transmission paths identified in the WECC Regional Reliability Standard.

Both Regional Reliability Standards therefore satisfied the statutory criteria for consideration as Regional Reliability Standards because their requirements are more stringent than the corresponding NERC Reliability Standards.

In its June 8, 2007 order approving eight WECC Regional Reliability Standards that included WECC-PRC-STD-001-1 and WECC-PRC-STD-003-1 — Protective Relay and Remedial Action

Scheme Misoperation, FERC directed WECC to make conforming changes to the standards based on the shortcomings identified in NERC's evaluation of the standards, as follows:

1. Remove the sanctions table that is inconsistent with the NERC Sanction Guidelines and add Violation Risk Factors and Violation Severity Levels;
2. Conform the effective dates of standards to the NERC Reliability Standards, stating they should become effective on the first day of following quarter upon regulatory approval;
3. Include requirements that are included in the measures in the requirements section of the standards; and
4. For PRC-STD-003-1, resolve the conflict in definition between the WECC definition of "disturbance" and the NERC definition in the NERC Glossary of Terms.

Further, FERC supported NERC's conditions for approval that WECC meet its commitment to address the shortcomings over the course of the year.

Proposal PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation: The proposed Regional Reliability Standard, PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation, was submitted for approval to NERC on June 11, 2008 to replace the FERC-approved WECC-PRC-STD-001-1 and WECC-PRC-STD-003-1. In processing this proposed Regional Reliability Standard, WECC indicated it used its standards development procedure that existed at the time per its Regional Delegation Agreement with NERC.

In the proposed PRC-004-WECC-1 standard, WECC implemented the FERC and NERC directives noted above by deleting the sanctions table; including Violation Severity Levels, Violation Risk Factors, Measures and Time Horizons; conforming the effective date format to that of the NERC Reliability Standards; and conforming the overall format of the standard to that of the NERC Reliability Standards.

WECC also identified the need for the timely mitigation of relaying problems and implemented such actions under the Reliability Management System (RMS) for its major transfer paths. PRC-004-WECC-1 incorporates the RMS criteria and provides:

1. More robust requirements for review and analysis of all operations of those elements by operating and system protection personnel, and
2. Timely actions that must be taken to ensure that misoperations of those elements are not repeated.

Further, WECC explained that PRC-004-WECC-1 continues to be more stringent than the continent-wide NERC Reliability Standards, including NERC's corresponding PRC-004-1.

NERC Reliability Standard PRC-003-1 has requirements for Regional Reliability Organizations to establish procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations but does not address the owners of the transmission and generation facilities. The NERC Reliability Standard PRC-004-1 has requirements for Protection System Misoperations but does not provide for the additional requirements as listed in PRC-004-WECC-1. For example:

- NERC Reliability Standard PRC-004-1, R1 requires the Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature;

- R2 requires that Generator Owners analyze their generator Protection System Misoperations, and develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature; and,
- R3 requires that Transmission Owners, any Distribution Providers that own a transmission Protection System, and Generator Owners provide to their Regional Reliability Organization (Regional Entity), documentation of their Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's (Regional Entity's) procedures developed per PRC-003-1, Requirement R1.
- Proposed Regional Reliability Standard, PRC-004-WECC-1, goes beyond the continent-wide NERC Reliability Standard by requiring that Transmission Owners and Generator Owners review and analyze all Protection System and remedial action scheme operations, including all trips, within 24 hours, and analyze all operations within 20 business days to determine whether a Misoperation has occurred per R1.1 and R1.2.
- R2 of the proposed WECC standard requires that Transmission Owners and Generator Owners perform specific actions for each Misoperation of the Protection System or remedial action scheme. R3 requires that Transmission Owners and Generation Owners submit Misoperation incident reports to WECC within 10 business days for identification of either Misoperations or the subsequent replacement or repairs of either a protection system or remedial action scheme.

In addition, WECC made other modifications to the standard not included in the FERC and NERC directives:

- WECC is proposing four defined terms for approval:

  Functionally Equivalent Protection System (FEPS) — A Protection System that provides performance as follows:

  - Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards.
  - Each Protection System may have different components and operating characteristics.

  Functionally Equivalent RAS (FERAS) — A Remedial Action Scheme (RAS) that provides the same performance as follows:

  - Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards.
  - Each RAS may have different components and operating characteristics.

  Security-Based Misoperation — A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.

  Dependability-Based Misoperation — The absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.

These terms are not in the NERC Glossary of Terms and will be added to the glossary upon approval of PRC-004-WECC-01. In addition, WECC eliminated its definition of "disturbance" that conflicted with the term defined in the NERC Glossary of Terms.

Also, PRC-STD-001-1 was retracted because the requirements are covered under existing NERC Reliability Standards. Specifically:

- Requirements B-WR1-a,b, and c are covered under NERC's Reliability Standard PRC-001-1 — System Protection Coordination;
- Requirement B-WR1-d is now covered in PRC-004-WECC-1; and,
- Requirement B-WR1-e is covered under TOP-005-1 — Operational Reliability Information.

Finally, PRC-STD-003 was renumbered to PRC-004-WECC-1 to make both the NERC PRC-004-1 and the WECC's PRC-004-WECC-1 standards applicable to similar entities. NERC PRC-003-1 is currently applicable to the RRO.

NERC 45-Day Posting: In June 11, 2008 WECC submitted the seven Tier 1 replacement standards for NERC evaluation. NERC posted the seven proposed Regional Reliability Standards for a 45-day public posting from April 4–May 20, 2008. The standard did not receive any substantial comments during the NERC posting and WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting.

NERC Evaluation: In accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*, approved by the Regional Reliability Standards Working Group, NERC provided its evaluation of the WECC proposed standard PRC-004-WECC-1 to WECC on July 30, 2008 (found in Appendix 4 to this report). In this report NERC made several recommendations to the proposed standard PRC-004-WECC-1 to which WECC responded in an August 18, 2008 letter (Appendix 5):

- NERC suggested adding clarity to the requirements and the applicability sections of the proposed standard by removing explanatory text from the requirements and ensuring that requirements apply to only those identified in the applicability section. In its response, WECC acknowledged that the standard drafting team included explanatory text in the requirement section in an attempt to clarify the requirements; however, WECC feels that the duplication does not adversely impact the applicability, or clarity of the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.
- NERC suggests that technical clarity is needed in R2, R2.1, R2.2.1, and R2.2.2. NERC believes there is sufficient ambiguity in the interplay between the main and sub-requirements that could be remedied by streamlining the requirement language. WECC replied that the requirements in the PRC-004-WECC-1 standard are clearly written and that industry stakeholders did not submit any comments questioning the clarity of the standard.

NERC staff believes WECC responded adequately to NERC's suggestions by agreeing to consider them at the next opportunity for revision.

Supporting Documents:

- Appendix 1 — Regional Reliability Standard Submittal Request
- Appendix 2 — Standard Development Roadmap
- Appendix 3 — Consideration of Comments document on NERC's posting of the regional standard
- Appendix 4 — NERC Evaluation of WECC Regional Standards
- Appendix 5 — WECC Response to NERC Evaluation
- Appendix 6 — WECC Response to FERC Comments
- Appendix 7 — WECC Consideration of Comment Reports
- Appendix 8 — WECC Standards Drafting Team
- Appendix 9 — WECC Balloting

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standard Submittal Request

Region: Western Electricity Coordinating Council

Regional Standard Number: PRC-004-WECC-1

Regional Standard Title: Protection System and Remedial Action Scheme Misoperation

Date Submitted: June 10, 2008

Regional Contact Name: Steven L. Rueckert

Regional Contact Title: Director of Standards

Regional Contact Telephone Number: (801) 582-0353

Request (check all that apply):

- ☒ Approval of a new standard
- ☐ Revision of an existing standard
- ☒ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

- ☒ Yes April 16, 2008
- ☐ No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:

To page 1 resource links

The purpose of the PRC-004-WECC-1 standard is to create a permanent replacement standard for PRC-STD-001-1 and PRC-STD-003-1. PRC-004-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when PRC-STD-001-1 and PRC-STD-003-1 were approved as NERC reliability standards. The new standard addresses the following areas:

1. Requirements for investigating operations to check for Misoperations.
2. Mitigation requirements after security-based Misoperations for redundant or non-redundant Protection Systems or Remedial Action Schemes.
3. Mitigation requirements after dependability-based Misoperations that do not adversely affect the reliability of the Bulk Electric System.

Several significant changes were made to PRC-STD-001 and PRC-STD-003 and they are itemized here:

1. PRC-STD-003 was renumbered to PRC-004-WECC-1. This makes both the PRC-004 and the Regional PRC-004-WECC-1 standards applicable to similar entities. PRC-003 is applicable to the RRO.

2. Standard PRC-STD-001 will be retracted because the requirements are covered by other standards per description below:

    a. PRC-STD-001 requirements B-WR1-a,b,c are covered under PRC-001
    b. PRC-STD-001 requirement B-WR1-d is covered in the new standard PRC-004-WECC-1
    c. PRC-STD-001 requirement B-WR1-e is covered under TOP-005-1

Concise statement of the justification of the request:

The PRC-004-WECC-1 regional reliability standard is more stringent than the continent-wide reliability standard (Standard PRC-004-1 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations). The new standard addresses the following areas:

1. Requirements for investigating operations to check for Misoperations.
2. Mitigation requirements after security-based Misoperations for redundant or non-redundant Protection Systems or Remedial Action Schemes.
3. Mitigation requirements after dependability-based Misoperations that do not adversely affect the reliability of the Bulk Electric System.

The NERC standard PRC-003-1 has requirements for Regional Reliability Organizations to establish procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations but does not address the owners of the transmission and generation facilities. The NERC standard PRC-004-1 has requirements for Protection System Misoperations but does not provide for the additional requirements as listed in PRC-004-WECC-1. The WECC Transmission Paths listed in the table titled "Major WECC Transfer Paths in the Bulk Electric System" and WECC RAS listed in table titled "Major WECC Remedial Action Schemes (RAS)" of PRC-004-WECC-1 are significant components for reliable delivery of power in the Western Interconnection. Protection System Misoperations and failures can cause reductions to the System Operating Limits (SOL) for those paths, and thus limit transfers between remotely located generation in the Western Interconnection and population/load centers. WECC identified the need for the timely mitigation of relaying problems and implemented such actions under the Reliability Management System (RMS). PRC-004-WECC-1 incorporates the RMS criteria and provides:

1. More robust requirements for review and analysis of all operations of those elements by operating and system protection personnel, and
2. Timely actions that must be taken to ensure that Misoperations of those elements are not repeated.

This standard is designed to minimize the SOL reductions required to maintain reliable Western Interconnection operation.

Other — please attach or include as separate files:

- The text of the regional reliability standard in MS Word format that:
  - has either been, or is anticipated to be, approved by the regional entity's board, and
  - is in a format consistent with the NERC template for reliability standards.
- An implementation plan.
- The regional entity standard drafting team roster.
- The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.
- The final ballot results, including a list of significant minority issues that were not resolved, and
- For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

Completed Actions	Completion Date
1. Post Draft Standard for initial industry comments	September 21, 2007
2. Drafting Team to review and respond to initial industry comments	November 29, 2007
3. Post second Draft Standard for industry comments	November 29, 2007
4. Drafting Team to review and respond to industry comments	January 23, 2008
5. Post Draft Standard for Operating Committee approval	January 23, 2008
6. Operating Committee ballots proposed standard	March 6, 2008
7. Post Draft Standard for WECC Board approval	March 12, 2008
8. Post Draft Standard for NERC comment period	April 14, 2008
9. WECC Board approved proposed standard	April 16, 2008
10. NERC comment period ended	May 20, 2008
11. Drafting Team completes review and consideration of the NERC industry comments	May 30, 2008

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for PRC-STD-001-1 and PRC-STD-003-1. PRC-004-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when PRC-STD-001-1 and PRC-STD-003-1 were approved as NERC reliability standards. The new standard addresses the following areas:

4. Requirements for investigating operations to check for Misoperations.
5. Mitigation requirements after security-based Misoperations for redundant or non-redundant Protection Systems or Remedial Action Schemes.
6. Mitigation requirements after dependability-based Misoperations that do not adversely affect the reliability of the Bulk Electric System.

Several significant changes were made to PRC-STD-001 and PRC-STD-003 and they are itemized here:

3. PRC-STD-003 was renumbered to PRC-004-WECC-1. This makes both the PRC-004 and the Regional PRC-004-WECC-1 standards applicable to similar entities. PRC-003 is applicable to the RRO.

4. Standard PRC-STD-001 will be retracted because the requirements are covered by other standards per description below:

    a. PRC-STD-001 requirements B-WR1-a,b,c are covered under PRC-001
    b. PRC-STD-001 requirement B-WR1-d is covered in this standard PRC-004-WECC-1
    c. PRC-STD-001 requirement B-WR1-e is covered under TOP-005-1

The WECC Operating Committee approved the PRC-004-WECC-1 standard as a permanent replacement standard for PRC-STD-001-1 and PRC-STD-003-1 on March 6, 2008. The WECC Board of Directors approved this standard April 16, 2008. The WECC Board of Directors recommends that the NERC Board of Trustees approve the PRC-004-WECC-1 as a permanent replacement standard for PRC-STD-001-1 and PRC-STD-003-1. In addition, the WECC Board of Directors recommends that the NERC Board of Trustees submits the standard to FERC for approval.

Justification for a Regional Standard

The NERC standard PRC-003-1 has requirements for Regional Reliability Organizations to establish procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations but does not address the owners of the transmission and generation facilities. The NERC standard PRC-004-1 has requirements for Protection System Misoperations but does not provide for the additional requirements as listed in PRC-004-WECC-1. The WECC Transmission Paths listed in the table titled "Major WECC Transfer Paths in the Bulk Electric System" and WECC RAS listed in table titled "Major WECC Remedial Action Schemes (RAS)" of PRC-004-WECC-1 are significant components for reliable delivery of power in the Western Interconnection. Protection System Misoperations and failures can cause reductions to the System Operating Limits (SOL) for those paths, and thus limit transfers between remotely located generation in the Western Interconnection and population/load centers. WECC identified the need for the timely mitigation of relaying problems and implemented such actions under the Reliability Management System (RMS). PRC-004-WECC-1 incorporates the RMS criteria and provides:

3. More robust requirements for review and analysis of all operations of those elements by operating and system protection personnel, and
4. Timely actions that must be taken to ensure that Misoperations of those elements are not repeated.

This standard is designed to minimize the SOL reductions required to maintain reliable Western Interconnection operation.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. NERC Board approval request	June 2008
2. Request FERC approval	June 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

Functionally Equivalent Protection System (FEPS): A Protection System that provides performance as follows:

- Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards.
- Each Protection System may have different components and operating characteristics.

Functionally Equivalent RAS (FERAS): A Remedial Action Scheme (RAS) that provides the same performance as follows:

- Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards.
- Each RAS may have different components and operating characteristics.

Security-Based Misoperation: A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.

Dependability-Based Misoperation: **Is** the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.

A. Introduction

1. **Title:** Protection System and Remedial Action Scheme Misoperation

2. **Number:** PRC-004-WECC-1

3. **Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

4. **Applicability**

   4.1. Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled "Major WECC Transfer Paths in the Bulk Electric System" provided at http://www.wecc.biz/Docs/Documents/Table%20Major%20Paths%204-28-08.doc and "Major WECC Remedial Action Schemes (RAS)" provided at http://www.wecc.biz/Docs/Documents/Table%20Major%20RAS%204-28-08.doc.

   4.2. Generator Owners that own RAS listed in the Table titled "Major WECC Remedial Action Schemes (RAS)" provided at http://www.wecc.biz/Docs/Documents/Table%20Major%20RAS%204-28-08.doc.

   4.3. Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled "Major WECC Transfer Paths in the Bulk Electric System" provided at http://www.wecc.biz/Docs/Documents/Table%20Major%20Paths%204-28-08.doc and "Major WECC Remedial Action Schemes (RAS)" provided at http://www.wecc.biz/Docs/Documents/Table%20Major%20RAS%204-28-08.doc.

5. **Effective Date:** On the first day of the second quarter following applicable regulatory approval.

B. Requirements

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)."

R.1. System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R1.1. System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.

R1.2. System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.

R.2. Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or

Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:

R2.1. If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.2. If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.2.1. Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.

R2.2.2. The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.

R2.3. If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.3.1. When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.

R2.3.2. When FERAS is not available, then

2.3.2.1. The Generator Owners shall adjust generation to a reliable operating level, or

2.3.2.2. Transmission Operators shall adjust the SOL and operate the facilities within established limits.

R2.4. If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.

R2.4.1. Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or

R2.4.2. Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R.3. Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R3.1. Identification of a Misoperation of a Protection System and/or RAS,

R3.2. Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

C. Measures

Each measure below applies directly to the requirement by number.

M1. Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.

M1.1 Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.

M1.2 Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.

M2. Transmission Owners and Generation Owners shall have evidence for the following.

M2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2 Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.

M2.2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2.2 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.

M2.3 The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.

M2.3.1 The Transmission Owner shall have evidence that it removed the associated Element from service.

M2.3.2 The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

M2.4 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.

M2.4.1 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

M2.4.2 Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

M3. Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

M3.1 Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

M3.2 Completion of repair or replacement of Protection System and/or RAS that misoperated.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 The Performance-reset Period is one calendar month.

1.3 Data Retention

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R1

Lower	**Moderate**	**High**	**Severe**
System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days.	System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days.	System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days.	System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days.

R2.1 and R2.2.1

Lower	**Moderate**	**High**	**Severe**

The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.3

Lower	**Moderate**	**High**	**Severe**
The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.2.2 and R2.4

Lower	**Moderate**	**High**	**Severe**

The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.

R3.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days.

R3.2

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion.

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1	

Appendix 3

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Report Form for WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation

The PRC-004-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the PRC-004-WECC-1 Standard. This Standard was posted for a 45-day public comment period from April 4, 2008 through May 20, 2008. NERC distributed the notice for this posting on April 7, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were two sets of comments from four companies representing three of the ten Industry Segments as shown in the table on the following pages.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the Standard can be viewed in their original format at:

http://www.nerc.com/~filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Manager of Regional Standards, Stephanie Monzon at Stephanie.monzon@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is described in the NERC Regional Reliability Standards Development Procedure: ftp://www.nerc.com/pub/sys/all_updl/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Dean Bender	Bonneville Power	✓									
2.	Annette Bannon	PPL Generation, LLC					✓	✓				
3.	Jon Williamson	PPL EnergyPlus						✓				
4.	John Cummings	PPL EnergyPlus						✓				
5.	Tom Olson	PPL Montana, LLC					✓					

Index to Questions, Comments, and Responses

1. **Was the WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation developed in a fair and open process, using the Process for Developing and Approving WECC Standards?**

Summary Consideration:

Commenter	Yes	No	Comment
Dean Bender	X		
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson	X		PPL believes that this standard provides good rules on equipment misoperations.
Response: Thank you for your support.			
Response:			

2. **Does the WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Commenter	Yes	No	Comment
Dean Bender		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
Response:			

3. **Does the WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation pose a serious and substantial threat to public health, safety, welfare, or national security?**

Summary Consideration:

Commenter	Yes	No	Comment
Dean Bender		X	
Response: Thank you.			

Commenter	Yes	No	Comment
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
Response:			

4. **Does the WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

Summary Consideration:

Commenter	Yes	No	Comment
Dean Bender		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
Response:			

5. **Does the WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation meet at least one of the following criteria?**

   - **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
   - **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
   - **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Commenter	Yes	No	Comment

Commenter	Yes	No	Comment
Dean Bender	X		
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
Response:			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Evaluation of Western Electricity Coordinating Council (WECC) Regional Standards

Executive Summary
July 30, 2008

On June 11, 2007, the WECC submitted the following seven regional standards for NERC evaluation to replace eight original WECC regional standards approved by NERC and FERC in 2007:

- BAL-002-WECC-1 — Contingency Reserves,
- FAC-501-WECC-1 — Transmission Maintenance,
- IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief,
- PRC-004-WECC-1— Protection System and Remedial Action Scheme Misoperation,
- TOP-007-WECC-1 — System Operating Limits,
- VAR-002-WECC-1 — Automatic Voltage Regulators and
- VAR-501-WECC-1 — Power System Stabilizer

NERC posted these seven proposed regional standards for a 45-day public posting beginning April 4–May 20, 2008. The standards received several comments during the NERC public posting. WECC supplied NERC with its responses to the comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting. WECC submitted these standards for NERC evaluation on June 11, 2008.

In accordance with NERC's *Rules of Procedure* and the *Regional Reliability Standards Evaluation Procedure* approved by the Regional Reliability Standards Working Group, NERC performed a review of the WECC proposed standards. The intent of this document is to provide WECC with NERC's feedback regarding their regional standards.

In this review, NERC presents a summary of observations for each proposed WECC regional standard. In Appendix A, NERC includes a redlined copy of each proposed regional standard with detailed comments included. NERC believes WECC has satisfied its procedural obligations as outlined in Appendix C of its Regional Delegation Agreement. However, NERC offers concerns and suggestions regarding several of the proposed regional standards that are discussed below.

Summary of Findings

BAL-002-WECC-1 — Contingency Reserves

In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

1. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

2. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

    R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

    R1.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

    R1.2. Capable of fully responding within ten minutes.

    In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

3. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

4. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

FAC-501-WECC-1 — Transmission Maintenance

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

1. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

2. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

1. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

2. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

3. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

1. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

2. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

3. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

4. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

TOP-007-WECC-1 — System Operating Limits

1. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

2. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

VAR-002-WECC-1 — Automatic Voltage Regulators

1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

   More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

VAR-501-WECC-1 — Power System Stabilizer

1. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a

justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

Conclusion

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC's Response to NERC's Comments
August 13, 2008
Draft

INTRODUCTION

WECC appreciates NERC staff's evaluation of the proposed WECC Regional Reliability Standards (RRSs) in accordance with NERC's Regional Reliability Standards Evaluation Procedure. These proposed WECC RRSs were developed as permanent replacements for the eight WECC Tier 1 RRSs that previously were approved by NERC and FERC. WECC asserts that the seven proposed standards contain all the performance elements of a Reliability Standard that are contained in the NERC Reliability Standards Development Procedure. In addition, the seven proposed standards address and implement the refinements directed by FERC's order on June 8, 2007 (see FERC Docket No.
RR07-11-000) and requested by NERC in its letter dated January 9, 2007. Finally, these proposed standards implement refinements to the approved WECC Tier 1 RRSs which were recommended during the previous expedited direct translation standard development processes.

The attached WECC responses individually address each NERC comment. However, many of the comments submitted by NERC staff relate to refinements that NERC has made to the format of its Reliability Standard Template. These refinements have not been formally approved by NERC, nor have they been transmitted to the regions for comment or additional information, and were therefore unavailable to WECC during the development process. Consequently, WECC has determined not to reopen the standards development process at this stage to address these non-substantive formatting concerns. In addition, during the standards development process, WECC staff twice requested that NERC staff review the proposed WECC standards. WECC did this to ensure that the WECC standard drafting teams were complying with NERC's Regional Reliability Standards Evaluation Procedure as well as its Reliability Standards Development Procedure. NERC did not perform the evaluation of these proposed standards until WECC had completed its Process for Developing and Approving WECC Standards. WECC intends to implement the requested formatting refinements and any potential FERC-directed changes during the next revision of these standards or the next FERC compliance filing.

The proposed WECC RRSs were considered and adopted pursuant to the Process for Developing and Approving WECC Standards. Unless they are approved in their current form, WECC will have to reinitiate the entire process. The consequences of rejecting these WECC RRSs in their entirety would be counterproductive to reliability in the Western Interconnection.

The proposed WECC RRSs will enhance reliability in the Western Interconnection and they will significantly improve the existing eight WECC RRSs because they:

1. Implement ordered NERC and FERC refinements to the existing standards ordered;
2. Eliminate conflicting NERC and WECC requirements contained in the existing RRSs;
3. Include all the Performance Elements of a Reliability Standard;
4. Clarify existing WECC RRSs;
5. Align better with NERC's Functional Model, and
6. Address industry stakeholder concerns.

Therefore, WECC requests the NERC staff recommend approval of these standards to the NERC Board and FERC.

WECC's responses to NERC's initial evaluation are provided in Attachment 1.

Attachment 1

NERC's Written Comments
July 30, 2008
WECC's Written Responses
August 13, 2008

Summary of Findings

BAL-002-WECC-1 — CONTINGENCY RESERVES

NERC COMMENT:
In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

5. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

WECC RESPONSE:
1. The requirements in the BAL-002-WECC-1 Standard as written are clear. Industry stakeholders did not submit any comments questioning the clarity of the standard, nor did they identify a need for an equation. The drafting team does not believe there is any ambiguity in the requirements.

NERC COMMENT:
6. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

R2. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

R2.2. Capable of fully responding within ten minutes.

WECC RESPONSE:
2. The drafting team wrote the BAL-002-WECC-1 Standard to permit load, Demand-Side Management (DSM), generation, or another resource technology that qualifies as Spinning Reserve or Contingency Reserve to be used as such. In the case of DSM, the declared amount would be required to respond automatically to frequency deviations and be capable of fully responding in 10

minutes. Loads and DSM are not allowed as Spinning Reserve because it is not permitted by the NERC Spinning Reserve definition. NERC requires that the BAL-002-WECC-1 Standard drafting team use NERC's Spinning Reserve definition. If NERC were to modify its Spinning Reserve definition to allow frequency responsive load tripping as part of a Balancing Authority's DSM, then its use would be permitted under the requirements of the BAL-002-WECC-1 Standard as proposed.

NERC COMMENT (continued):

In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

WECC RESPONSE (continued):

DSM that is deployable within 10 minutes is a subset of Interruptible Load. Interruptible load is defined in requirement R3.2 as an acceptable type of Contingency Reserve. As described previously, if NERC modifies its Spinning Reserve and Interruptible Load definitions, then it would be clear that qualifying DSM is permitted as part of Spinning and Contingency Reserves.

NERC COMMENT:

7. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

WECC RESPONSE:

3. The drafting team wrote a paper titled "WECC Standard BAL-002-WECC-1 Contingency Reserves" that provides an explanation supporting the modification. The paper was included as part of the standards approval package filed on June 11, 2008 with NERC.

NERC COMMENT:

8. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

WECC RESPONSE:

4. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>FAC-501-WECC-1 — TRANSMISSION MAINTENANCE</u>

NERC COMMENT:
It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

3. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

WECC RESPONSE:
1. "Transmission Facilities" is not a NERC-defined term in the NERC "Glossary of Terms Used in Reliability Standards" document, although "Transmission" and "Facility" are. The standard drafting team did not capitalize "transmission facilities" because it believes that the combination of these two defined terms was too limiting. WECC recognizes that this may create confusion and it proposes to address this issue during the next revision of these standards or the next FERC compliance filing.

NERC COMMENT:
4. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:
2. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

IRO-006-WECC-1 — QUALIFIED TRANSFER PATH UNSCHEDULED FLOW (USF) RELIEF

NERC COMMENT:

4. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

WECC RESPONSE:
1. The proposed IRO-006-WECC-1 Standard contains all the key reliability requirements and technical elements from the Unscheduled Flow Mitigation Plan (UFMP) that were included in IRO-STD-006-0. The proposed IRO-006-WECC-1 Standard uses NERC's Functional Model terminology to mitigate unscheduled flow during the next operating hour. It is not necessary to reference the remainder of the UFMP because the remaining items contain procedural requirements explaining "how," not "what." The proposed IRO-006-WECC-1 Standard includes requirements to reduce schedules, which then require adjustments to generation patterns. This prevents potential overloads during the next operating hour. Importantly, the requirements for mitigation of an actual (real-time) overload are contained in TOP-007-WECC-1.

NERC COMMENT:

5. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

WECC RESPONSE:

2. WECC acknowledges the difference between the NERC and WECC definitions for Transfer Distribution Factor (TDF). This is caused by the differences between the Eastern Interconnection Transmission Loading Relief process and the Western Interconnection UFMP. This difference in definitions exists even today between the existing FERC-approved IRO-STD-006-0 Standard and the NERC Glossary. Rejecting the proposed standard will not resolve this difference. WECC will work with NERC to resolve this and intends to make any necessary refinements during the next revision of this standard or the next FERC compliance filing. Despite the difference in the TDF definitions, **the proposed standard corrects a basic difference between the existing FERC-approved IRO-STD-006-0 Standard, which places reliability responsibilities upon the Load Serving Entities (LSEs), and the NERC Functional Model.** LSEs do not have the ability to ensure the implementation of the schedule adjustments required in the existing FERC-approved IRO-STD-006-0 Standard.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

5. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>PRC-004-WECC-1 — PROTECTION SYSTEM AND REMEDIAL ACTION SCHEME MISOPERATION</u>

NERC COMMENT:

5. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

WECC RESPONSE:

1. WECC recognizes that the standard drafting team included explanatory text in the requirement section in an attempt to clarify the requirements. However, the duplication does not adversely

impact the applicability, clarity, or the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

6. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

WECC RESPONSE:

2. WECC recognizes that the standard drafting team included System Operators and System Protection personnel in the requirements. R1. of PRC-004-WECC-1 states that, **"System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection Systems and RAS operations."** As written the requirement is sufficiently clear and well-defined to be enforceable on the entities in the Western Interconnection. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

7. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

WECC RESPONSE:

3. WECC recognizes that the standard drafting team included explanatory text in the requirement section that might be more appropriately included as a footnote. However, the text clarifies the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

8. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

WECC RESPONSE:

4. The requirements in the PRC-004-WECC-1 Standard are clearly written. Industry stakeholders did not submit any comments questioning the clarity of the standard. The alternative standard drafting formats or language used in this standard, are applicable exclusively to the Western Interconnection. These stylistic differences do not affect others and should not be a consideration for NERC approval.

<u>TOP-007-WECC-1 — SYSTEM OPERATING LIMITS (SOLs)</u>

NERC COMMENT:

3. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable

operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

WECC RESPONSE:

1. In the Western Interconnection, SOLs are designed so that during steady-state operations, with all lines in service, the system is at least two contingencies away from cascading. Therefore, exceeding an SOL for the 40 major paths identified in the TOP-007-WECC-1 Standard would not typically qualify as an Interconnection Reliability Operating Limit (IROL) under NERC's TOP-007-0 Standard. The standard drafting team created the TOP-007-WECC-1 Standard to limit the amount of time that a SOL may be exceeded for these very important paths, which makes the TOP-007-WECC-1 Standard more stringent than the NERC standard.

NERC COMMENT:

4. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

WECC RESPONSE:

2. The existing standard created confusion during system operation because system conditions may change the limiting conditions on a path. This is because the limit depends upon whether thermal, stability, or post transient limitations are the limiting factor. In addition, having different response times for paths (and sometimes for the same path depending on current outage conditions), complicates system operation, causing delays in responding to the path overload. This resulted in path operators implementing more drastic actions to respond to a contingency within 20 minutes, which may put the system at greater risk, particularly during heavy load periods such as summer. The standard drafting team determined that changing the standard from a 20-minute to a 30-minute response time is insignificant in terms of the probability of a next contingency occurring. Moreover, the drafting team believes that following a system disturbance, the system operators will be better able to identify what generation to ramp in order to be effective in mitigating the overload. This will also allow them to coordinate with others before implementing the generation ramps. Therefore, the simplification of the standard to one consistent 30-minute period improves reliability. It is important to recognize that in spite of extending the recovery period, the refinement should improve system reliability.

VAR-002-WECC-1 — AUTOMATIC VOLTAGE REGULATORS (AVRs)

NERC COMMENT:

4. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-002-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002a-1 Standard. The 98 percent in Requirement R1. of VAR-002-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002a-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring the AVR to be in service provides for time to start up generating facilities. It also allows for evaluation when the Generator Operators respond to unforeseen events.

NERC COMMENT (continued):
More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

WECC RESPONSE (continued):
NERC VAR-002-1a R1. permits the Generator Operator to operate in different modes by simply notifying the Transmission Operator. There are no restrictions on the length of time or reasons for operating in other modes. The WECC 1996 outage reports identified the lack of reactive support from generators with AVRs operating in modes other than voltage control as one of the causes of the WECC 1996 outages. The VAR-002-WECC-1 Standard limits the reasons and time for operating a generator without the AVR in service and controlling voltage, therefore it is more stringent than the NERC VAR-002-1a Standard.

NERC COMMENT

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the AVR in service). The use of peaking units adds to overall system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

VAR-501-WECC-1 — POWER SYSTEM STABILIZER (PSS)

NERC COMMENT:

4. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-501-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002b-1 Standard. The 98 percent in Requirement R1. of VAR-501-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002b-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring PSS to be in service provides time for evaluation and to start up generating facilities when Generator Operators respond to unforeseen events.

NERC COMMENT:

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the exiting standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the PSS in-service). Operating at low megawatt levels makes the PSS ineffective. The use of peaking units adds to over-all system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture PSS in service recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes that the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

(NERC) CONCLUSION

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC RESPONSE
WECC appreciates the opportunity to discuss NERC staff's initial evaluation and report in conference calls on August 4 and 5, 2008 and to provide the written clarifications and responses contained herein. We trust that WECC's responses, along with all the supporting documentation contained in WECC's submissions, provide the NERC staff a comprehensive basis for recommending NERC Board of Trustees approval of all proposed standards. Please direct any questions relating to WECC's response to WECC Director of Standards, Steve Rueckert at steve@wecc.biz or (801) 883-6878.

WECC Responses to FERC Staff Concerns and Questions
Regarding the Proposed WECC Tier 1 Standards
June 17, 2008

I. Contingency Reserves – BAL-002-WECC-1

A. Period of Contingency Reserve Restoration: Does the proposed standard modify the current standard to provide a longer period of time of 90 minutes rather than 60 minutes?

Yes, the requirement to restore contingency reserves within 60 minutes was eliminated in the proposed standard. The current standard requires the restoration of contingency reserves within the first 60 minutes following an event. By eliminating this requirement in the proposed standard, WECC adopts the NERC default standard that requires the restoration of contingency reserves within 90 minutes from the end of the disturbance recovery period.[2]

The 60 minute restoration period required by the current standard was developed and used under a manual interchange transaction structure among vertically integrated utilities. As the electric utility industry restructured, there has been a substantial increase in the number of market participants and interchange transactions.[3] To accommodate the increase in number of interchange transactions and market participants an electronic tagging system was implemented in the Western Interconnection. The adoption of an electronic tagging system that accommodates multiple market participants and a large number of interchange transactions made the current mid-hour reserve restoration more cumbersome and made the inappropriate rejection of reserve restoration transactions more likely because such transactions are outside the electronic tagging cycle.

Eliminating the 60 minute reserve restoration requirement and adopting the NERC requirements results in more efficient communication among Balancing Authorities (BAs) because it aligns the restoration of contingency reserves with the electronic tagging system approval cycle. Adopting the NERC contingency reserve restoration requirements reduces the potential for reserve transactions being inappropriately rejected resulting in improved communication among BAs resulting in improved reliability.

B. Shedding of Firm Load: Does the proposed standard change the treatment of the shedding of firm load compared to the current standard?

No, both standards allow for the shedding of firm load under limited circumstances. The addition of requirement R3.4 in the proposed standard clarified the process. During capacity and energy emergencies, a BA or Reserve Sharing Group (RSG) may use load as non-spinning reserves; that is BAs and RSGs will not drop load to maintain their non-spinning reserve requirement. Rather they will use load as part of their non-spinning contingency reserves.

[2] See NERC Standard BAL-002-0 Requirement R6 and WECC Standard BAL-STD-002-0 WR1.d.
[3] Balancing Authorities in the Western Interconnection approve between 2,500 and 4,500 interchange transactions per day.

This standard emphasizes the responsibility of serving customer load first while at the same time protecting the reliability of the Western Interconnection. Even during capacity and energy emergencies, BAs and RSGs are required to comply with the spinning reserve requirements.

C. Deliverability of Contingency Reserves: Does the proposed standard require that contingency reserves be deliverable?

Yes, nothing has changed with respect to the deliverability of contingency reserves.

D. Interruptible Imports: In the current standard the sink BA is required to carry an additional amount of contingency reserves equal to the amount of interruptible imports. Does the proposed standard have the same requirement?

Yes, the term interruptible imports was eliminated from the proposed standard. It was replaced with the added requirement R1.2 which requires that "If the Source BA designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink BA shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s)." This is an improvement from the current standard because it eliminates ambiguity in the term interruptible imports.

E. Demand Side Management: Did the drafting team comply with FERC Order 693 to explicitly allow demand-side management (DSM) to be used for reserves?

Yes, DSM that is deployable within 10 minutes is a subset of interruptible load. Interruptible load is defined in requirement R3.2 as an acceptable type of contingency reserve.

II. Qualified Transfer Path Unscheduled Flow Relief- IRO-006-WECC-1

A. Is the proposed standard intended to address an actual (real time) overload situation?

No, a different standard TOP-007-WECC-1 covers actual (real time) overload situations. The proposed IRO-006-WECC-1 standard includes requirements to reduce schedules, which requires adjustments to generation patterns, to prevent potential overloads during the next operating hour.

B. Should the Unscheduled Flow Mitigation Plan (UFMP) be incorporated in the IRO-006-WECC-1 by reference?

No, the key reliability portions from the UFMP are incorporated in the proposed standard. It is not necessary to reference the remainder of the UFMP.

C. Does the WECC UFMP need to be updated?

Yes, WECC has initiated the process of updating its UFMP.

III. System Operating Limits—TOP-007-WECC-1

A. Could the language in TOP-007-WECC-1 allow for the system to be less than two contingencies away from cascading and more specifically one contingency away from cascading?

No, the proposed standard is designed such that path operations must be at least two contingencies away from cascading during steady state operations. In real time operations when System Operating Limits (SOL) are exceeded for periods not to exceed 30 minutes, there may be system conditions that are less than two contingencies away from cascading.

B. Could IRO-005-2 Requirements R3 and R5 be interpreted that the power system is being operated two contingencies away from a cascading outage while WECC TOP-007-WECC-1 requirement R1 results in the power system being operated one contingency away from a cascading outage?

No, IRO-005-2 requirements R3 and R5 are consistent with the requirements in TOP-007-WECC-1. In the Western Interconnection SOLs are developed in such a manner that the system operation is at least two contingencies away from a cascading failure. This is implicit in the identification of the SOL derivation. If, however, there is a flow that exceeds the SOL, Transmission Operators (TOP) and Reliability Coordinators (RC) must take proactive immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the transmission path exceed the SOL for more than 30 minutes, thus protecting the system from potential cascading for a subsequent contingency.

C. Do SOL changes within the hour extend the time for compliance?

No, SOL changes within an operating hour do not extend the time for compliance.

IV. Automatic Voltage Regulators and Power System Stabilizers – VAR-002-WECC-1 and VAR-501-WECC-1

A. How does VAR-002-WECC-1 coordinate with the new NERC Standard VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules?

VAR-002-WECC-1 contains specific, more restrictive, requirements on generator operators regarding the operation of Automatic Voltage Regulators (AVR) that are not contained in the NERC Standard VAR-002-1. The reasons for these more restrictive requirements are to support transfer capabilities in the Western Interconnection and to address the insufficient supply of reactive power identified as a cause of the 1996 system disturbances in the Western Interconnection. The drafting team designed the VAR-002-WECC-1 Standard to limit the reasons for operating AVRs in a mode that does not control voltage and the amount of time permitted for such operations. Generator operators are still required to comply with all the requirements contained in NERC VAR-002-1.

B. Are Power System Stabilizers (PSS) included in either of these standards?

Yes, VAR-501-WECC-1 contains requirements regarding the in-service operation of PSS.

C. Why were the AVR and PSS replacement period extended to two years from 15 months?

The amount of time to replace AVR and PSS was lengthened to accommodate the approval and procurement time frames for AVR and PSS for nuclear power plants, which are two years.

V. Transmission Maintenance – FAC-501-WECC-1

A. Does the FAC-501-WECC-1 standard reduce the number of lines that are subject to this standard to the SOL limiting factors from the lines and facilities associated with the 40 paths thereby reducing the obligation for maintenance?

No, there is no change in the number of lines or facilities subject to the proposed FAC-501-WECC-1 standard.

- I agree with that the owner(s) should report misoperations instead of the operating agent(s) of the paths

Reply: No Reply necessary.

- Please clarify which elements need to be considered for misoperation reporting, just those which comprise the paths or any elements which can affect the SOL of a path

Reply: Similar to the previous RMS standards, only the elements listed in the tables "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)" need be reported. Other elements that may affect path SOLs are covered under other standards. We do not propose any modification.

- The Measures contained in Section M2 appear to be repetitive

Reply: The drafting team agrees that it may appear repetitive. The intent is to maintain a one-to-one relationship between the Requirements and the Measures for clarity of reporting. We do not propose any modification.

- The standard refers to "Misoperation Reports". Will WECC provide a standard reporting form?

Reply: Yes, the WECC Compliance Monitor will provide a standard reporting form. The existing RMS forms will be used until they are superseded.

- Section D. 1.4 refers to the submittal of misoperation and followup reports. Are the 10 day filing requirements in consecutive days or business days?

Reply: We will change the standard to indicate business days.

Nicholas Klemm - Western Area Power Administration

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1) The title and purpose of this standard is defined as reviewing misoperation but the requirement R1 says review all operations. We think it is unnecessarily burdensome to have to review all operations since the vast majority of operations are correct operations. We would recommend that there be no requirement for reviewing the correct operations.

Reply: Incorrect or questionable operations are generally easily detected, but unless each operation is evaluated, there is no assurance that incorrect operations are identified. We do not propose any modification.

2) R1.1 requires that all operations be reviewed within one day. This is unnecessary and burdensome. Our suggestion would be allow one week to review. Daily review requirement mean having one expert on hand every day, 365 days a year, can not fall sick and can not miss

the work without being non-compliant.

Reply: This requirement does not require detailed analysis. Trained System Operating personnel can classify most operations as correct or incorrect almost immediately. The draft standard was revised to clarify purpose, responsibility, and timing.

3) R2.2.1 provides a 22 hours window for action. I am not sure what is the rational for 22 hours. We would suggest one day as the more appropriate so as to allow the work to be completed by end of the next day.

Reply: The 22 hour window is the same criterion that is currently used in the RMS. This is to try to ensure that a misoperation that is a result of any daily loading cycle is mitigated before the opportunity for a similar misoperation. We do not propose any modification.

4) M1.1 requires evidence of having reviewed. What will constitute an acceptable evidence?

Reply: The owner's evidence to comply with PRC-004 M1and M2 is acceptable for this standard as well.

5) We also feel some of the 22 to 32 hours windows are unnecessarily tight going from low violation risk factor to sever. If one has a problem removing the protection system or RAS from service in 22 hours, there must be some very unusual circumstance. Our suggestion would be to extend it to at least 48 hours.

Reply: These time periods are duplicated from the RMS program. We do not propose any modification.

Tom Glock, Baj Agrawal
Arizona Public Service Co

The purpose of PRC-STD-003-1 has been lost in the replacement. Without the description in this draft, it is no longer clear that the standard is to meet PRC-003-1 R1.

Steve Alexanderson PE
Central Lincoln PUD

Reply: This standard is not intended to meet PRC-003-1. This standard is intended to replace the conditionally approved PRC-STD-003-1.

WECC Reliability Coordination Comments Work Group (RCCWG) Comments

WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation

The Reliability Coordinators are referred to in the WECC Standard PRC-004-WECC-1 in Requirement 2.3.2.2, with a requirement that "the WECC Reliability Coordinators shall derate the facilities to a reliable operating level" if a protection scheme cannot be repaired and placed back into service. In WECC, the path operator, not the WECC Reliability Coordinator determines and manages path limits. Removal of remedial action schemes and the resultant impact on paths and elements should be studied and known prior to real-time need as part of path management. As this requirement is WECC-specific, the assignment of this responsibility should remain with the path or element operator. The WECC Reliability Coordinators will receive a revised operating limit from the path operator, and will operate using that revised operating limit. Should the path or element operator not take action to reduce loading below the revised rating, the WECC Reliability Coordinator will monitor and, if needed, issue a directive that the path or element operator reduce loading using whatever method is necessary, including load shedding. The WECC RCCWG believes that this WECC standard should not be applicable to the WECC Reliability Coordinators.

Reply: The applicability to reliability coordinators has been removed from this standard and the responsibility for meeting 2.3.2.2 has been transferred to the Transmission Owner.

Measure M2.3.2 states that
"The Reliability Coordinator and GO shall have documentation describing all actions taken that adjusted generation or derated associated transmission facilities to a reliable operating level." The Path Operator (TOP) and Generator owner should retain documentation describing all actions taken to derate facilities and reduce generation. The WECC RCCWG notes that this measure assigns responsibility to the Reliability Coordinator. There is no requirement that the Reliability Coordinator monitor and record all generation redispatch. As previously noted, the WECC RCCWG believes that the Path Operator (TOP) and the Generator Owner should retain responsibility to meet the requirements of this standard. The Reliability Coordinator will become involved only if those requirements are not met.

Reply: The applicability to reliability coordinators has been removed from this standard and the responsibility for meeting 2.3.2.2 has been transferred to the Transmission Operator. (The functional model and TOP-002-2 R11 assign this responsibility to the Transmission Operator. I recommend 2.3.2 be Transmission Operator.)

WECC RCCWG
RCCWG Members Commenting on this draft standard:
Nancy Bellows, WACM
Terry Baker, PRPA
Paul Bleuss, CMRC
Jeremy Brownrigg, RDRC
Mike Gentry, SRP
Robert Johnson, PSC
Greg Tillitson

I commend the standard drafting team for a well written, easily understood draft standard. The original requirements of the predecessor standards all seem to be present along with the definitions an more specific Requirements make for an improved standard.

My comments are:

1. R.2.3 should say: "If the Protection system has a *Security-Based* Misoperation..."

Reply: The drafting team believes that either a Security- or Dependability-Based misoperation can apply to R2.3. If a Dependability-Based misoperation cannot be mitigated within 22 hours after *discovery and the reliability of the BES is at risk because another functionally equivalent system is unavailable, the mitigation of R2.3.1 and R2.3.2 must be implemented. The clarification was added to R2.3.*

2. R2.4 talked about actions to take when a Dependability-Based Misoperation occurs *with* one or more FEPS/FERAS. What about if *no* FEPS/FERAS exists?

Reply: Then R2.3 would apply.

3. The various Measures state that relay/RAS owners shall have "evidence" that various actions were taken (e.g., take a relay out-of-service). The word "evidence" can have a wide degree of interpretation for an auditor. For example, does evidence include producing the offending relay for an auditor/photographs/fingerprints? This opens the door to inconsistent auditing practices. I suggest that all instances of "evidence" should be replaced with "documentation."

Reply: This standard uses terminology consistent with the NERC standards. The owner's evidence to comply with PRC-004 Measures is acceptable for this standard as well. We do not propose any modifications.

4. Lastly, all of the Measures in PRC-004 are a dramatic increase in the documentation required, not present in the predecessor standards. So dramatic, that the standard really isn't about relay/RAS performance; it's about the paperwork. The standard is about the process, not the end result--greater reliability. Even my earlier comment about "documentation" rather than "evidence" does not focus on the important aspect of this exercise: higher reliability. It's a full-employment act for document management staff and lawyers. These new effective requirements for "evidence" are too burdensome.

Reply: This standard is an implementation of the already existing RMS program under the NERC Standard functional model. All such standards must have measurable requirements and violation severity levels. We do not propose modification.

Anonymous

4.1 and 4.2 Clarify which document contains the Tables, not just a link to WECC.

Reply: The appropriate link will be included in the final draft. The current draft has the tables included at the end of the body of the standard.

5.0 Make the effective date 90 days after approval (they could approve on the last day of a quarter, then it would be mandatory the next day).

Reply: We will make the standard effective the first day of the second quarter following the regulatory approval.

Requirements: Clarify that these requirements only apply to protection and RAS to those paths or schemes contained in the Tables. As written, it says it applies to the Owners, but doesn't say it applies only to the paths or schemes.

Reply: The Applicability section clearly identifies the impacted owners. We do not propose modification.

R.2.2.2 and R2.4.2 should still allow for operation of the elements at levels that meet NERC and WECC standards beyond the 20 day period. Or at least the RC should be able to allow.
Reply: This is an implementation of the existing RMS program and uses the same allowable time periods. We do not propose modification.

Adjust measures accordingly. Measures are about paperwork, not greater reliability. At some time, they system will collapse due to the paperwork, not instability.

Reply: The requirements are only slightly different than exist under the current RMS program. We do not propose modification.

Scott Peterson, SDG&E

The measurements are littered with references to reporting. Reporting is not mentioned in any of the Requirements. If the measurements are going to refer to reporting, the Requirements need to be specific in what the reporting requirements are.

Mike Gentry
Salt River Project

Reply: The standard was modified to have separate requirements (R3) and measures (M3) for reporting.

Comments from Bonneville Power Administration

WECC Standard PRC-004-WECC-1 Protection System and Remedial Action Scheme Misoperation

DEFINITIONS OF TERMS USED IN STANDARD

Dependability-Based Misoperation: Any of the following:
The absence of a Protection System or RAS operation when intended
A Protection System or RAS equipment failure is alarmed or indicated to operating personnel.
A Protection System or RAS equipment failure is discovered.

A Protection System or RAS equipment failure is alarmed or indicated to operating personnel should not be considered a Misoperation. It is an alarm that indicates that the equipment is compromised. The operating staff will take action to get the equipment repaired. If the operating staff determines that there isn't adequate RAS or protective system coverage, they will take the correct action to mitigate the situation. An alarm is not a misoperation.

A Protection System or RAS equipment failure is discovered is not a Misoperation - it is only a misoperation when it does not operate when required. If an equipment failure is discovered, it is repaired or replaced or mitigated by the operating staff. The failure of equipment should not be identified as a misoperation.

The definition of a 'Dependability-Based Misoperation' should simply read, "A Dependability-Based Misoperation is the failure of a Protection System or RAS to operate when intended."

Reply: The standard was modified to eliminate alarming.

B. Requirements
R.1. System Operating and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]
R1.1. System Operating personnel shall review all operations or alarms of Protection Systems and RAS within one business day.
R1.2. System Protection personnel shall analyze all operations or alarms of Protection Systems and RAS for correctness within 20 business days.
R1.2 should read, "System Protection personnel shall analyze all operations of Protection Systems and RAS for correctness within 20 business days." Most alarms for RAS are caused by communication fades on analog microwave systems. If you have a microwave communications system, you expect to see this type of alarm. Other types of common alarms are to notify the dispatcher when they should alter the arming status of the RAS. The System Operating Staff make an assessment of the alarm and will pull in the System Protection staff if further action is required.

Reply: The standard was modified to eliminate alarming.

R2.3.2.2 The Reliability Coordinators shall derate the facilities to a reliable operating level.

This sentence should read, R2.3.2.2. The Path Operator shall set the operating transfer capability (OTC) of the impacted path to a reliable operating level.

Reply: The applicability to reliability coordinators has been removed from this standard and the responsibility for meeting 2.3.2.2 has been transferred to the Transmission Operator. (The functional model and TOP-002-2 R11 assign this responsibility to the Transmission Operator. I recommend 2.3.2 be Transmission Operator.)

C. Measures
M1. Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations or alarms.
M1.1 Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations and alarms of Protection System and RAS within one business day.
M1.2 Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations and alarms of Protection System and RAS for correctness within 20 business days.

C.M1. should read, M1. Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.

Reply: The standard was modified to eliminate alarming.

Remove the word "alarms" from this measure.

C.M1.1 remove the words, “and alarms”.

C.M1.2 remove the words, “and alarms”.

Reply: The standard was modified to eliminate alarming.

M2. Transmission Owner and Generation Owner shall have evidence for the following.
M2.1 Transmission Owners and Generation Owners shall have evidence that they reported and removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

Reply: No reply necessary.

The definition of Dependability-Based Misoperation must be changed, otherwise every time there is a momentary communications alarm, or some other minor alarm, we'd have to remove equipment from service.

Reply: The standard was modified to eliminate alarming.

M2.3.2 The Reliability Coordinator and Generator Owner shall have documentation describing all actions taken that adjusted generation or derated associated transmission facilities to a reliable operating level.

"Derated" is not the correct term to use. Use Operating Transfer Capability (OTC) instead. Rating a transmission path is a complex process involving system studies and going through various WECC study groups. Setting a new OTC based upon current conditions, for example a complete RAS outage, does not change the official rating of the path. Also, "Reliability Coordinator" should be changed to "path operator."

Reply: The applicability to reliability coordinators has been removed from this standard and the responsibility for meeting 2.3.2.2 has been transferred to the Transmission Operator. The term SOL is used in place of “derated.” (The functional model and TOP-002-2 R11 assign this responsibility to the Transmission Operator. I recommend 2.3.2 be Transmission Operator.)

Comments from Bonneville Power Administration
Commenter: John Kerr, Electrical Engineer, Technical Operations

CONSIDERATION OF COMMENTS FOR PRC-004-WECC-1 — RELAY AND RAS MISOPERATIONS
COMMENTS WERE DUE JANUARY 2, 2008
JANUARY 18, 2008

The PRC-004-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the WECC PRC-004-WECC-1 Standard. This Standard was posted for a 30-day public comment period from November 29, 2007 through January 2, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard by posting comments on the WECC website. There were seven sets of comments from seven companies.

In this 'Consideration of Comments' document, stakeholder comments have been organized so that it is easier to see the responses associated with each comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Steve Rueckert at 801-582-0353 or at steve@wecc.biz. In addition, there is a WECC Appeals Process.

Comments and Responses

PRC-004-WECC-1

How can the repair or replacement at owners discretion in R2.1 occur when the repair or replacement measures in M2.2.2, M2.3, and M2.4 require 22 hours to 20 days for action?

richard.dernbach@ladwp.com

Reply: M2.1 is in response to R2.1, which requires that two or more functionally equivalent relay systems remain in service after the relay that misoperated is removed. With three or more equivalent relays in service prior to the misoperation of one of them, removing one from service leaves at least two relays in service which meets minimum redundancy requirements.

Comments on draft standard PRC-004-WECC-1 by Ron Forster and Jeanne Harshbarger, Substation Engineering, Puget Sound Energy

Extra word, p.1., Several Significant Changes…. Part 2.b. "is covered in the this standard"

Reply: The drafting team made the correction.

There is an inconsistency regarding the response time for System Operators, which shows up on:

p.5., B. Requirements, R1.1 "shall review all operations of Protection Systems and RAS to identify apparent Misoperations within 24 hours"
p.7., C. Measures, M1.1 "Shall have evidence that System Operations personnel reviewed all operations of Protection System and RAS within one business day"

Reply: The drafting team changed M1.1 to 24 hours to be consistent with R1.1.

p.10. R1, Lower, “did not review the Protection System Operation or RAS operation within one business day”

Reply: The drafting team changed VSL of R1 to 24 hours to be consistent with M1.1.

A confusing point on p.6., R2.2.2., “of the date of removal, or either remove the Element from service or disable the RAS.”

Reply: The drafting team modified R2.2.2 to clarify the requirement.

Concerning all of M2., since there are different requirements depending on whether the misoperation is security-based or dependability-based, should the measures reflect this?

Anonymous

Reply: The drafting team added a statement that each measure applies directly to the requirement by number.

We were hopeful that after reviewing the submitted comments from the first posting, the drafting team would remove or reduce the requirement for a 24-hour review of operations and the associated documentation evidence burden that results from this requirement. The latest draft does clarify that Operating personnel (we assume real-time) can sufficiently conduct this review. We believe that this activity does occur in all practicality absent having a specific requirement, but that having this requirement in the Standard is onerous from an evidence standpoint and goes beyond anything in the NERC Standards, which appear to be silent on this matter.

Rich Salgo - Sierra Pacific Resources Transmission

Reply: Documentation appears to be the primary concern. The drafting team believes that documentation is necessary. For example, the operator’s log that identifies the relay operation as suspicious would be sufficient documentation.

The drafting team realizes that regional standards have to be more restrictive than NERC reliability standards. The drafting team believes it important to remedy apparent relay or RAS misoperations before they can recur and in order to do that all operations have to be evaluated.

The listing of Major WECC Remedial Action Schemes needs to be updated. Items 14 and 15 involving SDGE are not applicable-

Bill Cook- San Diego Gas & Electric

Reply: Updating the RAS list is not intended to be part of the PRC-004-WECC-1 Standard development. The drafting team recommends that SDG&E submit a request using the WECC standards process to update the RAS list.

The Alberta Electric System Operator appreciates the opportunity to comment on this proposed standard and would like to offer the following comments:

The reporting schemes for Alberta Transmission Owners and Generation Owners to the WECC is under review in Alberta and future changes may be necessary.

The RAS scheme for Path 1 pertaining to curtailment of generation north of SOK should be reviewed for accuracy.

There seems to be a discrepancy between the wording in R1.1 and M1.1 where one refers to "within 24 hours" and the other "within one business day."

Thank you.

Anita Lee, P. Eng.
Manager, Operating Policies and Procedures
Alberta Electric System Operator (AESO)

Reply: Updating the RAS list is not intended to be part of the PRC-004-WECC-1 Standard development. The drafting team recommends that AESO submit a request using the WECC standards process to update the RAS list. The drafting team changed M1.1 to 24 hours to be consistent with R1.1.

R1.1.
"System Operators or System Protection personnel" should replace "System Operators"

Reply: The drafting team believes System Operator is correct. The operator's log that identifies the relay operation as suspicious would be sufficient documentation.

"24 hours" should be changed to one business day to match the measures of M1.1 and the Violation Severity Levels of Table R1.

Reply: The drafting team changed M1.1 to 24 hours to be consistent with R1.1.

M1.1
"System Operating personnel or System Protection personnel" should replace "System Operating personnel"

Reply: In reference to the "System Operators or System Protection personnel" question, it is the operator's responsibility for the initial review. The operator performs the initial review with whatever resources are needed, including protection personnel. However, the operator documents the operation, and protection personnel provide a more detailed analysis as needed.

2. Violation Severity Levels.
Table R1 uses a response time of one business day, which is not consistent with R1.1 (which says

24 hours)

Reply: Table R1 was changed to 24 hours to be consistent with R1.1.

Also, System Operating personnel or System Protection personnel" should replace "System Operating personnel " on each category (Lower, Moderate, High, Severe) on table R1

Reply: In reference to the "System Operators or System Protection personnel" question, it is the operator's responsibility for the initial review. The operator performs the initial review with whatever resources are needed, including protection personnel. However, the operator documents the operation, and protection personnel provide a more detailed analysis as needed.

D1.3 Data Retention
Should have the phrase, "or since the last audit, whichever is longer" stricken or a finite limitation to data retention expressed. The way this is phrased now, if no audit occurs, data retention is unlimited.

Reply: The drafting team has changed the standard to implement the comment.

The proposed standard PRC-004 fails by only defining two extreme ways in which a RAS can fail, Security Misoperations and Dependability Misoperation. This proposed standard does not acknowledge that responses by a RAS can exist between those two extremes. For a RAS that adjusts its response to try and match the magnitude of system events it is very nearly impossible to perfectly match the response to the inputs as quickly as system events require correction. As a result, such systems are usually programmed to trip more aggressively than necessary, preferring the added stability that such conservatism represents. That should not be considered misoperation, even if a thorough post-event analysis reveals that less generation could be dropped. This proposed standard makes no accommodation for that.

Reply: The commenter is correct that RAS are often designed to accommodate the worst credible contingencies. This standard is intended to apply when the RAS did not function as designed.

Leland McMillan

- Regarding the Table "Major WECC Remedial Action Schemes (RAS) (Revised September 19, 2007)", Page 15 of 17, please check and clarify whether presently generation tripping is still required north of the SOK cutplane in Alberta, for high East to West transfers on the Alberta – British Columbia Path 1. Please remove this sentence if no generation tripping is presently required north of the SOK cutplane in Alberta.

Reply: Updating the RAS list is not intended to be part of the PRC-004-WECC-1 Standard development. The drafting team recommends that TransAlta submit a request using the WECC standards process to update the RAS list.

- Also, for each RAS it will be useful to identify the applicable TO and/or GO in the RAS Table.

Reply: To implement the NERC functional model the applicability section was change from transmission and generation operators to the owners. The drafting team does not have the information to implement this recommendation. The applicability section 4 and the NERC functional registration identifies the entities that are required to comply with the standard. The drafting team recommends that TransAlta submit a request using the WECC standards process to modify the RAS list.

Comment posted by WECC Staff on behalf of Sudershan Srinivasan, TransAlta

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I am not certain about when the 22 hour clock starts. It starts when the system operator identifies a misoperations or when system protection analyze and identify the misoperations, which can be after 20 business day.

Reply: The 22 hour time limit begins when either the System Operating personnel or the System Protection personnel suspect or identify a Misoperation.

If system operator identifies a misoperation, then system protection still has 20 business days to analyze it.

Reply: The 20 business days analysis limit applies to the System Protection personnel if the System Operating personnel did not recognize a Misoperation. If the System Operating personnel indicate an apparent Misoperation but the System Protection personnel determine, within the allowed 22 hours, that a Misoperation did not occur no additional mitigation is required.

Malkiat Dhillon

From: Williams, Benjamin E (ET)
Sent: Monday, December 17, 2007 11:06 AM
To: Buchholz, Kristine (ET)
Subject: RE: Time Sensitive Action Required - WECC Standard PRC-004-WECC-1 - Comments Due January 2, 2008

One could choose to read the applicability as applying to the entire system of a Transmission Owner, as long as that TO owns just one of the listed WECC Paths or Major RAS systems. That "loophole" needs to be closed in the language of this standard to make sure that this is no longer open for interpretation and is strictly limited to only those facilities that are actually listed.

Reply: The drafting team changed the Requirements to clarify that they apply only to major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” and the Major WECC Remedial Action Schemes (RAS)” listed on the web site.

-Ben Williams

Sandra, Tanyl has been on the committee that worked on the draft of this standard so she can correct me if my comments are off base. In any case, my comments are as follows:

<u>1. page 5 R1.1 refers to "all operations</u>"

I believe "all" needs to be clarified. I doubt that it is really intended to mean all in the sense that for every legitimate relay fault operation there are possibly hundreds of overreaching relay elements the operate or restrain at remote locations.

Reply: The drafting team changed the Requirements to clarify that System Operating personnel must review tripping of transmission elements and RAS operations. The analysis of operations of Protection Systems and RAS is left to Protection System personnel.

<u>2. page 6 R2.1 (and R2.2)</u>

I believe clarification is needed regarding "remaining in service" and "removing." Something like "if two or more FERAS remain in service AFTER the one that experienced the security-based misoperation has been removed from service, then ..."

What this really implies is that there must have been three FERAS to begin with.

Reply: R2.1 does apply only if three or more FERAS are normally in service.

<u>3. page 7 R.3 (and perhaps other places)</u>

PacifiCorp has had a case in which we neither repaired or replaced the system that misoperated. However, we returned to normal operation based on a procedural change. The change we made would prevent the same event from being able to happen in the future by requiring manual intervention by a relay tech before restoring the system to normal. The language as written makes no allowance for that type of fix. I recommend that language be incorporated that allows for other types of corrective actions. In our case, the procedure is not a particularly desirable long term solution because it requires manual intervention. However, it was a reasonable temporary fix because the whole scheme is being changed out in 2008.

Reply: The drafting team believes that changing operating procedures is essentially a design change and no change is required in the Standard.

Drafting Team PRC-004-WECC-1

FIRST NAME	LAST NAME	COMPANY
Frank	Ashrafi	Southern California Edison
Dean	Bender	Bonneville Power Administration
Dan	Buchanan	British Columbia Transmission Corporation
Simon	Cheng	Puget Sound Energy
Lane	Cope	Western Area Power Administration WAHQ
Richard	Curtner	Public Service Company of New Mexico
Malkiat	Dhillon	Sacramento Municipal Utility District
Gene	Henneberg	Sierra Pacific Resources Transmission
Michael	Ibold	Public Service Company of Colorado
Ken	Wilson	Western Electricity Coordinating Council
Jonathan	Meyer	Idaho Power Company
Bill	Middaugh	TriState Generation and Transmission Association, Inc.
Paul	Rice	Western Electricity Coordinating Council
Craig	Richart	Arizona Public Service Company
Mike	Ryan	Portland General Electric Company
Dan	Shield	Alberta Electric System Operator
Randy	Spacek	Avista Corporation
Jonathan	Sykes	Salt River Project
Edward	Taylor	Pacific Gas and Electric Company
Tanyl	Tinhof	PacifiCorp.
Joe	Uchiyama	US Department of the Interior USDO
Dan	Wheeler	Northwestern Energy
Mike	Yang	Portland General Electric Company

OPERATING COMMITTEE

PRC-004-WECC-1

SP - State and Provincial
TP - Transmission Provider
TC - Transmission Customer
IS - Interested Stakeholder

Name of Organization	Name of Voting Member	Voting Class	YES	NO	Abstain
Alberta Electric System Operator (AESO)	Doug Hincks	TP	X		
AltaLink L.P. (ALTA)	Rick Spyker	TP	X		
Aquila Networks-WPC (WPE)	Al Logan	TC			X
Arizona Public Service (AZPS)	Mark Hackney (alternate)	TP	X		
Arizona Public Service (AZPS)	David Hansen	TC	X		
ATCO Electric Ltd. (ATCO)	Blaine Beisiegel	TP	X		
Avista Corp	Scott J. Kinney (alternate)	TP		X	
Basin Electric Power Cooperative (BEPC)	Becky Kern	TC			X
Bear Energy LP (BEAR)	Jeff Winkler (alternate)	TC	X		
Black Hills Power and Light Company (BHPL)	Pam Pahls	TP	X		
Bonneville Power Administration-Power Bus Line (BPAP)	Fran Halpin	TC	X		
Bonneville Power Administration-TBL (BPAT)	Don Watkins	TP	X		
British Columbia Hydro and Power Authority (BCHA)	Clement Ma	TC	X		
British Columbia Transmission Corporation (BCTC)	Devinder Ghangass	TP	X		
California Department of Water Resources (CDWR)	Glenn Solbert	TC	X		
California Energy Commission (CEC)	Bill Chamberlain (alternate)	SP	X		
California ISO (CISO)	James McIntosh	TP	X		
California Mexico Reliability Center	Greg Tillitson - TC	IS	X		
Calpine Corporation (CALP)	Frank Obertance	TC	X		
Colorado Springs Utilities (CSU)	Steve Schaarschmidt	TP	X		
Constellation Energy Commodities Group, Inc. (CCG)	Mary Lynch	TC			
Coral Power LLC	Michael Wong	TC			X
Deseret Generation & Transmission Co-op (DGT)	Phil Tice	TC	X		
Deseret Generation & Transmission Co-op (DGT)	L'Dee Curtis	TP	X		
Dynegy, Inc. (DYN)	Brian Theaker	TC	X		
El Paso Electric Company (EPE)	Jose Nevarez	TP	X		
Eugene Water & Electric Board (EWEB)	Dean Ahlsten	TC			X
Fortis Energy Marketing & Trading Group (FEMT)	Jay Alexander	TC	X		
Gila River Power, L.P. (PGR)	Kenneth Parker	TC			X
Great Basin Transmission, LLC (GBT)	Ali Amirali	TC	X		
Highland Energy LLC	Bryan Bradshow	IS			X
Idaho Power Company (IPC)	Tessia Park	TP	X		
Idaho Power Company (IPC)	Shaun Jensen	TC			
Metropolitan Water District of Southern California (MWD)	Garry Chinn	TP	X		
Mirant Americas, Inc. (MIR)	John Stout	TC	X		
Modesto Irrigation District (MID)	Toxie Burriss	TP		X	
Morgan Stanley Capital Group Inc.	Patrick Murray (alternate)	TC	X		
Northern California Power Agency (NCPA)	Fred Young	TC			X
NorthWestern Energy (NWMT)	Mark Donaldson (alternate)	TP	X		
NRG Power Marketing, Inc. (NRG)	Robert Bailey	TC		X	
Pacific Gas & Electric (PG&E)	Kris Bucholz	TP	X		
Pacific Gas & Electric (PG&E)	Joe Minkstein	TC	X		
PacifiCorp (PACM)	John Apperson	TC	X		
PacifiCorp (PAC)	Robert Williams	TP	X		
Platte River Power Authority (PRPA)	John R. Powell	TP	X		
Portland General Electric (PGE)	Mike Ryan	TP	X		
Portland General Electric (PGE)	John Jamieson (alternate)	TC	X		
Powerex (PWX)	Mike Goodenough	TC	X		
PPL EnergyPlus, LLC (PPLE)	John Cummings (Alternate)	TC	X		
PPM Energy, Inc. (PPM)	Diana Scholtes (alternate)	TC			X
Public Service Company of Colorado (PSC)	Robert Johnson	TP	X		
Public Service Company of Colorado (PSC)	Steve Buening	TC	X		
Public Service Company of New Mexico (PNM)	Keith Nix	TP	X		
Public Service Company of New Mexico (PNM)	David Miller	TC	X		
Public Utility District No. 1 of Chelan County (CHPD)	Hugh Owen	TC	X		
Public Utility District No. 1 of Douglas County (DOPD)	Henry E. (Hank) LuBean	TP	X		
Public Utility District No. 2 of Grant County (GCPD)	Greg Lange	TC	X		
Puget Sound Energy, Inc. (PSE)	Gary Nolan (alternate)	TP	X		

Board of Directors

April 16-18, 2008 **Voting Summary**

Coronado, CA **PRC-004-WECC-1**

Last Name	First Nam	Organization	Class
Anderson	Bob	Non-affiliated Director	Non-Affiliated
Areghini	David	Salt River Project	Class 1
Barbash	Carolyn	Sierra Pacific Power Company	Class 1
Beyer	Lee	California Public Utilities Commission	Class 5
Brown	Duncan	Calpine Corporation	Class 3
Campbell	Ric	Utah Public Service Commission	Class 5
Cauchois	Scott	CADRA	Class 4
Chamberlain	Bill	California Energy Commission	Class 5
Cleary	Anne	Mirant Americas, Inc.	Class 3
Conway	Teresa	Powerex Corp.	Class 6
Coughlin	John	Non-affiliated Board Member	Non-Affiliated
Dearing	Bill	Grant County PUD	Class 2
Ferreira	Richard	TANC Executive Advisor	Class 2
Grantham-Richards	Maude	Farmington Electric Utility System	Class 2
Gutting	Scott	Energy Strategies, LLC	Class 4
Kelly	Nancy	Utah Committee of Consumer Services	Class 4
King	Jack	Non-affiliated Board Member	Non-Affiliated
LaFond	Steve	The Boeing Company	Class 4
Little	Doug	British Columbia Transmission Corporation	Class 6
McMaster	Dale	Alberta Electrical System Operator	Class 6
Moya	Jesus	Comision Federal de Electricidad	Mexico
Newton	Tim	Non-affiliated Director	Non-Affiliated
Sharpless	Jananne	Non Affiliated Board Member	Non-Affiliated
Smith	Marsha	Idaho Public Utilities Commission	Class 5
Stout	John	Mariner Consulting	Class 3
Tarplee	Gary	Southern California Edison	Class 1
Thuston	Tim	Williams Power	Class 3
Weis	Larry	Turlock Irrigation District	Class 2
VanZandt	Vicki	Bonneville Power Administration	Class 1
Zaozirny	Lori Ann	British Columbia Utilities Commission	Class 6

The Board Members listed above voted whether to approve PRC-004-WECC-1.
The Regional Reliability Standard was approved unanimiously.

TOP-007-WECC-1 — System Operating Limits

Action: TOP-007-WECC-1 — System Operating Limits — **Approve**

Proposed Effective Date: On the first day of the first quarter, after applicable regulatory approval.

Summary Conclusion and Recommendation:

- NERC recommends approval of TOP-007-WECC-1 — System Operating Limits on the basis that the Regional Reliability Standard is more stringent than the corresponding NERC Reliability Standard, TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations, thus satisfying the statutory criteria for a Regional Reliability Standard. The 30-minute response limit to SOL violations is more stringent than the corresponding NERC Reliability Standard.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

Background*:* FERC approved Regional Reliability Standard WECC-TOP-STD-007-0 — Operating Transfer Capability on the basis that it is more stringent than the continent-wide NERC Reliability Standard TOP-007-0. Specifically, Regional Reliability Standard WECC-TOP-STD-007-0 established a more restrictive time limitation on exceeding the operating transfer capability to 20 minutes for stability limited paths and 30 minutes for thermally limited paths whereas NERC's Reliability Standard TOP-007-0 R2 establishes that "following a Contingency or other event that results in an *IROL* violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but no longer than 30 minutes." WECC further explained that WECC-TOP-STD-007-0 has requirements for reducing actual flows to within System Operating Limits on major WECC transfer paths in the bulk power system. Therefore, WECC-TOP-STD-007-0 satisfied the statutory criteria for consideration as a Regional Reliability Standard through requirements that are more stringent than the corresponding NERC Reliability Standard.

In its June 8, 2007 Order approving eight WECC Regional Reliability Standards that included WECC-TOP-STD-007-0, FERC directed WECC to make conforming changes to the standard based on the shortcomings identified in NERC's evaluation of the standard and on its own motion, as follows:

1. Remove the sanctions table that is inconsistent with the NERC Sanction Guidelines and add Violation Risk Factors and Violation Severity Levels;
2. Address the inconsistencies with regional definitions for Operating Transfer Capability and Disturbance;
3. Conform the standard to the NERC Reliability Standards, specifically the effective date, that should conform to language stating it should become effective on the first day of following quarter upon regulatory approval;
4. Clarify the reference to business day;

5. Clarify any inconsistency between WR1.b and corresponding Measure WM1; and,
6. Ensure the requirements currently set forth in measures WM1 are set forth in the requirements and that corresponding measures simply quantify the frequency, duration and magnitude of the violations as determined by the requirements.

Further, FERC supported NERC's conditions that WECC meet its commitment to address the shortcomings over the course of the year.

Proposal TOP-007-WECC-1 — System Operating Limits: The proposed Regional Reliability Standard, TOP-007-WECC-1, was submitted to NERC on June 11, 2008 for approval, replacing the FERC-approved WECC-TOP-STD-007-0. In processing the proposed Regional Reliability Standard, WECC indicated it utilized its standards development procedure that existed at the time per its Regional Delegation Agreement with NERC.

Depending on the current system conditions, the limits for the paths identified in the TOP-007-WECC-1 standard are SOLs that would not result in cascading outages. There is no NERC requirement to return the transmission system to within SOL limits, only a requirement to report the event to the Reliability Coordinator. TOP-007-WECC-1 specifically applies to the major paths in the Western Interconnection regardless of whether the limit is defined as an IROL or the less severe SOL. WECC explained that TOP-007-WECC-1 continues to be more stringent than the continent-wide NERC Reliability Standard, TOP—007-0 because it provides a maximum time limit of 30 minutes to return the system to within an SOL. The continent-wide NERC Reliability Standard requires this action only for an IROL.

In the proposed TOP-007-WECC-1 standard WECC implemented the FERC and NERC directives associated with the Order approving WECC-TOP-STD-007-0. The proposed replacement standard, TOP-007-WECC-1, was modified such that it no longer contains the sanctions table; includes Violation Severity Levels, Violation Risk Factors, Measures and Time Horizons; conforms the effective date format to that of the NERC Reliability Standards; conforms the overall format of the standard to that of the NERC Reliability Standards; eliminated the proposed terms that conflicted with the NERC Glossary of Terms; eliminated the reference to business day; and clarifies the requirements and corresponding measurements. WECC also modified the standard numbering to conform to the NERC Reliability Standards numbering convention.

While WECC made the directed conforming changes, they also significantly modified requirements of the WECC-TOP-STD-007-0 standard. These modifications included:

- Eliminating several requirements addressing operating limits, stability, and system contingency response on the basis that they are covered in NERC Reliability Standards FAC-011-1- — System Operating Limits Methodology for the Operations Horizon, FAC-014-1 — Establish and Communication System Operating Limits, TOP-004 -1 — Transmission Operations, and TOP-002-2 — Normal Operations Planning.
- Eliminating the distinction between thermally and stability limited paths and adopting the 30 minute limitation on exceeding SOLs for each. The standard drafting team justified that there is no substantial difference between thermally-limited paths and stability-limited paths when considering risk to the transmission system and only one time limit has been used, 30 minutes, corresponding to the response time for thermally limited paths.

- Translating two requirements from WECC-TOP-STD-007-0 that require Transmission Operators take immediate action to reduce actual power flow across the path such that at no time shall the power flow for the transmission path exceed the SOL for more than 30 minutes (R1), and requiring Transmission Operators to not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path's SOL when the Transmission Operator implements its real-time schedules for the next hour (R2).

NERC 45-Day Posting: On June 11, 2008 WECC submitted seven Tier 1 replacement standards for NERC evaluation, which posted for a 45-day public posting from April 4–May 20, 2008. The standards received few comments during the NERC posting. WECC supplied NERC with its response to comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting.

NERC Evaluation: In accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*, approved by the Regional Reliability Standards Working Group, NERC provided its evaluation of the WECC proposed standard TOP-007-WECC-1 to WECC on July 30, 2008 (Appendix 4). In this report NERC made several recommendations to the proposed standard TOP-007-WECC-1 to which WECC responded in an August 18, 2008 letter (Appendix 5):

- NERC staff expressed concern that the proposed standard no longer proposes more stringent requirements than the corresponding NERC Reliability Standard. Further, the elimination of most of the requirements on the basis that they are covered by existing NERC Reliability Standards leaves little substantive requirements in the proposed Regional Reliability Standard. WECC explained the remaining requirements in the proposed standard, TOP-007-WECC-1 pertain to managing SOLs and not IROLs as in the NERC Reliability Standard, TOP-007-0.

- FERC expressed concern that the proposed standard, TOP-007-WECC-1, could allow for the system to be less than two contingencies away from cascading and more specifically one contingency away from cascading. In their response to FERC WECC explained their concerns (Appendix 6) that the proposed standard is designed such that transmission paths must be at least two contingencies away from cascading during steady state operations. Further, in real time operations when SOLs are exceeded for periods not to exceed 30 minutes there may be system conditions that are less than two contingencies away from cascading.

- NERC made suggestions to improve the clarity of the requirements in TOP-007-WECC-1 and to add a table containing the Violation Severity Levels to conform to the NERC Reliability Standards.

NERC staff believes WECC responded adequately to NERC's suggestions by agreeing to consider these changes at the next opportunity for revision of this standard.

Supporting Documents:

- Appendix 1 — Regional Reliability Standard Submittal Request
- Appendix 2 — Standard Development Roadmap
- Appendix 3 — Consideration of Comments document on NERC's posting of the regional standard
- Appendix 4 — NERC Evaluation of WECC Regional Standards

- Appendix 5 — WECC Response to NERC Evaluation
- Appendix 6 — WECC Response to FERC Comments
- Appendix 7 — WECC Consideration of Comment Reports
- Appendix 8 — WECC Standards Drafting Team
- Appendix 9 — WECC Balloting

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Regional Reliability Standard Submittal Request

Region: Western Electricity Coordinating Council

Regional Standard Number: TOP-007-WECC-1

Regional Standard Title: System Operating Limits

Date Submitted: June 10, 2008

Regional Contact Name: Steven L. Rueckert

Regional Contact Title: Director of Standards

Regional Contact Telephone Number: (801) 582-0353

Request (check all that apply):

- ☒ Approval of a new standard
- ☐ Revision of an existing standard
- ☒ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

- ☒ Yes April 16, 2008
- ☐ No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:

The purpose of this standard is to create a permanent replacement standard for TOP-STD-007-0. TOP-007-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when TOP-STD-007-0 was approved as a NERC reliability standard.

Concise statement of the justification of the request:

To page 1 resource links

The NERC standard (TOP-STD-007-0) has requirements for reducing actual flows to within System Operating Limits (SOL) on Major WECC Transfer Paths in the Bulk Electric System. The major paths listed in the Table titled “Major WECC Transfer Paths in the Bulk Electric System” are significant components for reliable delivery of power in the Western Interconnection. System Operating Limits for these paths are critical because they transfer energy from remotely located generation to population/load centers. The entities of the Western Interconnection through studies and operation see the need for optimizing the capacity of these paths. The lack of redundant transmission in these corridors raises the level of scrutiny for these paths; therefore, this standard is designed to add emphasis to reducing flows to within SOL to maintain reliable Western Interconnection operation.

NERC TOP-007-0 (R2) requires the Transmission Operator to return its transmission path flows to within Interconnection Reliability Operating Limits (IROL) as soon as possible, but no longer than 30 minutes following a contingency or event. This requirement applies only to those limits that are defined as IROL. Depending on the current system conditions, the limits for the paths identified in this TOP-007-WECC-1 standard are SOL that would not result in cascading outages. There is no NERC requirement to return the transmission system to within SOL limits, only a requirement to report to the Reliability Coordinator. TOP-007-WECC-1 specifically applies to the major paths in the Western Interconnection regardless of whether the limit is defined as an IROL or the less severe SOL.

In Order No. 693 and Docket No. RR07-11-000, the FERC expressed concern that TOP-007-0 could be interpreted as allowing a system operator to respect IROLs in one of two ways: (1) allowing IROL to be exceeded during normal operations, *i.e.*, prior to a contingency, provided that corrective actions are taken within 30 minutes; or (2) allowing IROL to be exceeded only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes. FERC explained that the system could be one contingency away from potential cascading failure if operated under the first interpretation and two contingencies away from cascading failure under the second interpretation. FERC directed NERC to conduct a survey on IROL practices and actual operating experiences of managing within IROL. The survey results will provide guidance on the frequency, duration, and magnitude of IROL violations and whether these IROL violations occur during normal or contingency conditions.

WECC and NERC responded to FERC’s June 8, 2007 Order (Docket No. RR007-11-000) in its compliance filing of July 9, 2007. The compliance filing document is posted with this standard for reference. On November 2, 2007, FERC accepted NERC’s and WECC’s filing and indicated that the filling satisfactorily responds to the Commission’s directive, *Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications*, 119 FERC ¶ 61,260 (2007) at P 108.

The requirement for keeping Net Scheduled Interchange within a path’s SOL is not covered in the NERC Reliability Standards. Scheduling transmission paths beyond their limits could adversely affect actual flows on parallel paths by creating unscheduled flow that may jeopardize system reliability.

Other — please attach or include as separate files:

- The text of the Regional Reliability Standard in MS Word format that:
    - has either been, or is anticipated to be, approved by the regional entity's board, and
    - is in a format consistent with the NERC template for reliability standards.

- An implementation plan.
- The regional entity standard drafting team roster.
- The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.
- The final ballot results, including a list of significant minority issues that were not resolved, and
- For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

Completed Actions	Completion Date
1. Post Draft Standard for initial industry comments	September 21, 2007
2. Drafting Team to review and respond to initial industry comments	November 16, 2007
3. Post second Draft Standard for industry comments	November 16, 2007
4. Drafting Team to review and respond to industry comments	January 25, 2008
5. Post Draft Standard for Operating Committee approval	January 25, 2008
6. Operating Committee ballots proposed standard	March 6, 2008
7. Post Draft Standard for WECC Board approval	March 12, 2008
8. Post Draft Standard for NERC comment period	April 14, 2008
9. WECC Board approved proposed standard	April 16, 2008
10. NERC comment period ended	May 20, 2008
11. Drafting Team completed review and consideration of NERC industry comments	May 30, 2008

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for TOP-STD-007-0. TOP-007-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when TOP-STD-007-0 was approved as a NERC reliability standard.

This draft standard incorporates the following refinements to the first draft of TOP-007-WECC-1 in response to comments received during the first comment period that ended November 5, 2007 and the second comment period that ended January 2, 2008.

1. Refine R1 to remove the requirement to return a path to within its limit in 20 minute for SOLs based upon Transient Stability and Voltage Stability.
2. Refine R2 to limit the compliance period for the Net Scheduled Interchange to the real-time schedules for the next hour.
3. Refine R2 to permit 30 minutes to adjust Net Scheduled Interchange when SOLs reduce within 20 minutes of the start of the hour.
4. Change M2 based upon the refinements to R2.
5. Base the violation severity levels for R2 upon magnitude.

This version of the TOP-007-WECC-1 standard is for NERC Board of Trustee ballot. The WECC Board of Directors approved the standard April 16, 2008. WECC Operating Committee approved the standard March 6, 2008. The WECC Board of Directors and Operating Committee request that the NERC Board of Trustees approve the TOP-007-WECC-1 Standard as a permanent replacement standard for TOP-STD-007-0 and that the NERC Board of Trustees submits the standard to FERC for approval and replacement of TOP-STD-007-0.

Justification for a Regional Standard

The NERC standard (TOP-STD-007-0) has requirements for reducing actual flows to within System Operating Limits (SOL) on Major WECC Transfer Paths in the Bulk Electric System. The major paths listed in the Table titled "Major WECC Transfer Paths in the Bulk Electric System" are significant components for reliable delivery of power in the Western Interconnection. System Operating Limits for these paths are critical because they transfer energy from remotely located generation to population/load centers. The entities of the Western Interconnection through studies and operation see the need for optimizing the capacity of these paths. The lack of redundant transmission in these corridors raises the level of scrutiny for these paths; therefore, this standard is designed to add emphasis to reducing flows to within SOL to maintain reliable Western Interconnection operation.

NERC TOP-007-0 (R2) requires the Transmission Operator to return its transmission path flows to within Interconnection Reliability Operating Limits (IROL) as soon as possible, but no longer than 30 minutes following a contingency or event. This requirement applies only to those limits that are defined as IROL. Depending on the current system conditions, the limits for the paths identified in this TOP-007-WECC-1 standard are SOL that would not result in cascading outages. There is no NERC requirement to return the transmission system to within SOL limits, only a requirement to report to the Reliability Coordinator. TOP-007-WECC-1 specifically applies to the major paths in the Western Interconnection regardless of whether the limit is defined as an IROL or the less severe SOL.

In Order No. 693 and Docket No. RR07-11-000, the FERC expressed concern that TOP-007-0 could be interpreted as allowing a system operator to respect IROLs in one of two ways: (1) allowing IROL to be exceeded during normal operations, *i.e.*, prior to a contingency, provided that corrective actions are taken within 30 minutes; or (2) allowing IROL to be exceeded only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes. FERC explained that the system could be one contingency away from potential cascading failure if operated under the first interpretation and two contingencies away from cascading failure under the second interpretation. FERC directed NERC to conduct a survey on IROL practices and actual operating experiences of managing within IROL. The survey results will provide guidance on the frequency, duration, and magnitude of IROL violations and whether these IROL violations occur during normal or contingency conditions.

WECC and NERC responded to FERC's June 8, 2007 Order (Docket No. RR007-11-000) in its compliance filing of July 9, 2007. The compliance filing document is posted with this standard for reference. On November 2, 2007, FERC accepted NERC's and WECC's filing and indicated that the filling satisfactorily responds to the Commission's directive, *Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications*, 119 FERC ¶ 61,260 (2007) at P 108.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. NERC Board approval request	June 2008
2. Request FERC approval	June 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

A. Introduction

1. **Title:** **System Operating Limits**
2. **Number:** TOP-007-WECC-1
3. **Purpose:** When actual flows on Major WECC Transfer Paths exceed System Operating Limits (SOL), their associated schedules and actual flows are not exceeded for longer than a specified time.
4. **Applicability**

   4.1. Transmission Operators for the transmission paths in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" provided at:

   http://www.wecc.biz/Docs/Documents/Table%20Major%20Paths%204-28-08.doc.
5. **Effective Date:** On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. When the actual power flow exceeds an SOL for a Transmission path, the Transmission Operators shall take immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the Transmission path exceed the SOL for more than 30 minutes. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. The Transmission Operator shall not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path's SOL when the Transmission Operator implements its real-time schedules for the next hour. For paths internal to a Transmission Operator Area that are not scheduled, this requirement does not apply. *[Violation Risk Factor: Low] [Time Horizon: Real-time Operations]*

R2.1. If the path SOL decreases within 20 minutes before the start of the hour, the Transmission Operator shall adjust the Net Scheduled Interchange within 30 minutes to the new SOL value. Net Scheduled Interchange exceeding the new SOL during this 30-minute period will not be a violation of R2.

C. Measures

M1. Evidence that actual power flow has not exceeded the SOL for the specified time limit in R1.

M2. Evidence that Net Scheduled Interchange has not exceeded the SOL when the Transmission Operator implements real-time schedules as required by R2.

a. Evidence that Net Scheduled Interchange was at or below the new SOL within 30-minutes of when the SOL decreased.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Self-report for each incident within three-business day
- Self-report quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

Reset Period: One calendar month.

1.3 Data Retention

The Transmission Operators shall keep evidence for Measure M.1 through M2 for three years plus current, or since the last audit, whichever is longer.

1.4. Additional Compliance Information

2. Violation Severity Levels

For Requirement R1:

2.1. Lower: There shall be a Lower Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.2. Moderate: There shall be a Moderate Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.3. High: There shall be a High Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.4. Severe: There shall be a Severe Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

For Requirement R2:

2.1. Lower: There shall be a Lower Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above the path's SOL but is less than or equal to 105% of the path's SOL.

2.2. Moderate: There shall be a Moderate Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above 105% of the path's SOL but less than or equal to 110% of the path's SOL.

2.3. High: There shall be a High Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above 110% of the path's SOL.

2.4 Severe: None

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for TOP-STD-007-0	

Attachment 1 – TOP-007-WECC-1

Violation Severity Level Table

Percentage by which 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%	Lower	Moderate	Moderate	High
greater than 5%, up to and including 10%	Moderate	Moderate	High	High
greater than 10%, up to and including 15%	Moderate	High	High	Severe
greater than 15%, up to and including 20%	High	High	Severe	Severe
greater than 20%, up to and including 25%	High	Severe	Severe	Severe
greater than 25%	Severe	Severe	Severe	Severe

* Measured after 30 continuous minutes of actual flows in excess of SOL.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Report Form for WECC Standard TOP-007-WECC-1 — System Operating Limits

The TOP-007-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the TOP-007-WECC-1. This Standard was posted for a 45-day public comment period from April 4, 2008 through May 20, 2008. NERC distributed the notice for this posting on April 7, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were two sets of comments from four companies representing four of the ten Industry Segments as shown in the table on the following pages.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the Standard can be viewed in their original format at:

http://www.nerc.com/~filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Manager of Regional Standards, Stephanie Monzon at Stephanie.monzon@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is described in the NERC Regional Reliability Standards Development Procedure: ftp://www.nerc.com/pub/sys/all_updl/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Chuck Westbrook	Bonneville Power	✓		✓		✓	✓				
2.	Annette Bannon	PPL Generation, LLC					✓	✓				
3.	Jon Williamson	PPL EnergyPlus						✓				
4.	John Cummings	PPL EnergyPlus						✓				
5.	Tom Olson	PPL Montana, LLC					✓					

Index to Questions, Comments, and Responses

1. **Was the WECC Standard TOP-007-WECC-1 – System Operating Limits developed in a fair and open process, using the Process for Developing and Approving WECC Standards?**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook	X		
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson	X		PPL believes this standard provides useful clarification of operating limits.
Response: Thank you for your support.			

2. **Does the WECC Standard TOP-007-WECC-1 – System Operating Limits pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

3. **Does the WECC Standard TOP-007-WECC-1 – System Operating Limits pose a serious and substantial threat to public health, safety, welfare, or national security?**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

4. **Does the WECC Standard TOP-007-WECC-1 – System Operating Limits pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

5. **Does the WECC Standard TOP-007-WECC-1 – System Operating Limits meet at least one of the following criteria?**

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook	X		
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Evaluation of Western Electricity Coordinating Council (WECC) Regional Standards

Executive Summary
July 30, 2008

On June 11, 2007, the WECC submitted the following seven regional standards for NERC evaluation to replace eight original WECC regional standards approved by NERC and FERC in 2007:

- BAL-002-WECC-1 — Contingency Reserves,
- FAC-501-WECC-1 — Transmission Maintenance,
- IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief,
- PRC-004-WECC-1— Protection System and Remedial Action Scheme Misoperation,
- TOP-007-WECC-1 — System Operating Limits,
- VAR-002-WECC-1 — Automatic Voltage Regulators and
- VAR-501-WECC-1 — Power System Stabilizer

NERC posted these seven proposed regional standards for a 45-day public posting beginning April 4–May 20, 2008. The standards received several comments during the NERC public posting. WECC supplied NERC with its responses to the comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting. WECC submitted these standards for NERC evaluation on June 11, 2008.

In accordance with NERC's *Rules of Procedure* and the *Regional Reliability Standards Evaluation Procedure* approved by the Regional Reliability Standards Working Group, NERC performed a review of the WECC proposed standards. The intent of this document is to provide WECC with NERC's feedback regarding their regional standards.

In this review, NERC presents a summary of observations for each proposed WECC regional standard. In Appendix A, NERC includes a redlined copy of each proposed regional standard with detailed comments included. NERC believes WECC has satisfied its procedural obligations as outlined in Appendix C of its Regional Delegation Agreement. However, NERC offers concerns and suggestions regarding several of the proposed regional standards that are discussed below.

Summary of Findings

BAL-002-WECC-1 — Contingency Reserves

In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

1. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

2. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

    R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

    R1.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

    R1.2. Capable of fully responding within ten minutes.

    In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

3. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

4. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

FAC-501-WECC-1 — Transmission Maintenance

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

1. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

2. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

1. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

2. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

3. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

1. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

2. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

3. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

4. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

TOP-007-WECC-1 — System Operating Limits

1. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

2. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

VAR-002-WECC-1 — Automatic Voltage Regulators

1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

   More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

VAR-501-WECC-1 — Power System Stabilizer

1. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a

justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

Conclusion

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC's Response to NERC's Comments
August 13, 2008
Draft

INTRODUCTION

WECC appreciates NERC staff's evaluation of the proposed WECC Regional Reliability Standards (RRSs) in accordance with NERC's Regional Reliability Standards Evaluation Procedure. These proposed WECC RRSs were developed as permanent replacements for the eight WECC Tier 1 RRSs that previously were approved by NERC and FERC. WECC asserts that the seven proposed standards contain all the performance elements of a Reliability Standard that are contained in the NERC Reliability Standards Development Procedure. In addition, the seven proposed standards address and implement the refinements directed by FERC's order on June 8, 2007 (see FERC Docket No.
RR07-11-000) and requested by NERC in its letter dated January 9, 2007. Finally, these proposed standards implement refinements to the approved WECC Tier 1 RRSs which were recommended during the previous expedited direct translation standard development processes.

The attached WECC responses individually address each NERC comment. However, many of the comments submitted by NERC staff relate to refinements that NERC has made to the format of its Reliability Standard Template. These refinements have not been formally approved by NERC, nor have they been transmitted to the regions for comment or additional information, and were therefore unavailable to WECC during the development process. Consequently, WECC has determined not to reopen the standards development process at this stage to address these non-substantive formatting concerns. In addition, during the standards development process, WECC staff twice requested that NERC staff review the proposed WECC standards. WECC did this to ensure that the WECC standard drafting teams were complying with NERC's Regional Reliability Standards Evaluation Procedure as well as its Reliability Standards Development Procedure. NERC did not perform the evaluation of these proposed standards until WECC had completed its Process for Developing and Approving WECC Standards. WECC intends to implement the requested formatting refinements and any potential FERC-directed changes during the next revision of these standards or the next FERC compliance filing.

The proposed WECC RRSs were considered and adopted pursuant to the Process for Developing and Approving WECC Standards. Unless they are approved in their current form, WECC will have to reinitiate the entire process. The consequences of rejecting these WECC RRSs in their entirety would be counterproductive to reliability in the Western Interconnection.

The proposed WECC RRSs will enhance reliability in the Western Interconnection and they will significantly improve the existing eight WECC RRSs because they:

1. Implement ordered NERC and FERC refinements to the existing standards ordered;
2. Eliminate conflicting NERC and WECC requirements contained in the existing RRSs;
3. Include all the Performance Elements of a Reliability Standard;
4. Clarify existing WECC RRSs;
5. Align better with NERC's Functional Model, and
6. Address industry stakeholder concerns.

Therefore, WECC requests the NERC staff recommend approval of these standards to the NERC Board and FERC.

WECC's responses to NERC's initial evaluation are provided in Attachment 1.

Attachment 1

NERC's Written Comments
July 30, 2008
WECC's Written Responses
August 13, 2008

Summary of Findings

BAL-002-WECC-1 — CONTINGENCY RESERVES

NERC COMMENT:
In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

5. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

WECC RESPONSE:
1. The requirements in the BAL-002-WECC-1 Standard as written are clear. Industry stakeholders did not submit any comments questioning the clarity of the standard, nor did they identify a need for an equation. The drafting team does not believe there is any ambiguity in the requirements.

NERC COMMENT:
6. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

> **R2.** Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
>
> **R2.1.** Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.
>
> **R2.2.** Capable of fully responding within ten minutes.

WECC RESPONSE:
2. The drafting team wrote the BAL-002-WECC-1 Standard to permit load, Demand-Side Management (DSM), generation, or another resource technology that qualifies as Spinning Reserve or Contingency Reserve to be used as such. In the case of DSM, the declared amount would be required to respond automatically to frequency deviations and be capable of fully responding in 10

minutes. Loads and DSM are not allowed as Spinning Reserve because it is not permitted by the NERC Spinning Reserve definition. NERC requires that the BAL-002-WECC-1 Standard drafting team use NERC's Spinning Reserve definition. If NERC were to modify its Spinning Reserve definition to allow frequency responsive load tripping as part of a Balancing Authority's DSM, then its use would be permitted under the requirements of the BAL-002-WECC-1 Standard as proposed.

NERC COMMENT (continued):

In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

WECC RESPONSE (continued):

DSM that is deployable within 10 minutes is a subset of Interruptible Load. Interruptible load is defined in requirement R3.2 as an acceptable type of Contingency Reserve. As described previously, if NERC modifies its Spinning Reserve and Interruptible Load definitions, then it would be clear that qualifying DSM is permitted as part of Spinning and Contingency Reserves.

NERC COMMENT:

7. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

WECC RESPONSE:

3. The drafting team wrote a paper titled "WECC Standard BAL-002-WECC-1 Contingency Reserves" that provides an explanation supporting the modification. The paper was included as part of the standards approval package filed on June 11, 2008 with NERC.

NERC COMMENT:

8. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

WECC RESPONSE:

4. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>FAC-501-WECC-1 — TRANSMISSION MAINTENANCE</u>

NERC COMMENT:
It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

3. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

WECC RESPONSE:
1. "Transmission Facilities" is not a NERC-defined term in the NERC "Glossary of Terms Used in Reliability Standards" document, although "Transmission" and "Facility" are. The standard drafting team did not capitalize "transmission facilities" because it believes that the combination of these two defined terms was too limiting. WECC recognizes that this may create confusion and it proposes to address this issue during the next revision of these standards or the next FERC compliance filing.

NERC COMMENT:
4. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:
2. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

IRO-006-WECC-1 — QUALIFIED TRANSFER PATH UNSCHEDULED FLOW (USF) RELIEF

NERC COMMENT:

4. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

WECC RESPONSE:
1. The proposed IRO-006-WECC-1 Standard contains all the key reliability requirements and technical elements from the Unscheduled Flow Mitigation Plan (UFMP) that were included in IRO-STD-006-0. The proposed IRO-006-WECC-1 Standard uses NERC's Functional Model terminology to mitigate unscheduled flow during the next operating hour. It is not necessary to reference the remainder of the UFMP because the remaining items contain procedural requirements explaining "how," not "what." The proposed IRO-006-WECC-1 Standard includes requirements to reduce schedules, which then require adjustments to generation patterns. This prevents potential overloads during the next operating hour. Importantly, the requirements for mitigation of an actual (real-time) overload are contained in TOP-007-WECC-1.

NERC COMMENT:

5. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

WECC RESPONSE:

2. WECC acknowledges the difference between the NERC and WECC definitions for Transfer Distribution Factor (TDF). This is caused by the differences between the Eastern Interconnection Transmission Loading Relief process and the Western Interconnection UFMP. This difference in definitions exists even today between the existing FERC-approved IRO-STD-006-0 Standard and the NERC Glossary. Rejecting the proposed standard will not resolve this difference. WECC will work with NERC to resolve this and intends to make any necessary refinements during the next revision of this standard or the next FERC compliance filing. Despite the difference in the TDF definitions, **the proposed standard corrects a basic difference between the existing FERC-approved IRO-STD-006-0 Standard, which places reliability responsibilities upon the Load Serving Entities (LSEs), and the NERC Functional Model.** LSEs do not have the ability to ensure the implementation of the schedule adjustments required in the existing FERC-approved IRO-STD-006-0 Standard.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

5. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

PRC-004-WECC-1 — PROTECTION SYSTEM AND REMEDIAL ACTION SCHEME MISOPERATION

NERC COMMENT:

5. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

WECC RESPONSE:

1. WECC recognizes that the standard drafting team included explanatory text in the requirement section in an attempt to clarify the requirements. However, the duplication does not adversely

impact the applicability, clarity, or the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

6. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

WECC RESPONSE:

2. WECC recognizes that the standard drafting team included System Operators and System Protection personnel in the requirements. R1. of PRC-004-WECC-1 states that, **"System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection Systems and RAS operations."** As written the requirement is sufficiently clear and well-defined to be enforceable on the entities in the Western Interconnection. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

7. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

WECC RESPONSE:

3. WECC recognizes that the standard drafting team included explanatory text in the requirement section that might be more appropriately included as a footnote. However, the text clarifies the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

8. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

WECC RESPONSE:

4. The requirements in the PRC-004-WECC-1 Standard are clearly written. Industry stakeholders did not submit any comments questioning the clarity of the standard. The alternative standard drafting formats or language used in this standard, are applicable exclusively to the Western Interconnection. These stylistic differences do not affect others and should not be a consideration for NERC approval.

<u>TOP-007-WECC-1 — SYSTEM OPERATING LIMITS (SOLs)</u>

NERC COMMENT:

3. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable

operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

WECC RESPONSE:

1. In the Western Interconnection, SOLs are designed so that during steady-state operations, with all lines in service, the system is at least two contingencies away from cascading. Therefore, exceeding an SOL for the 40 major paths identified in the TOP-007-WECC-1 Standard would not typically qualify as an Interconnection Reliability Operating Limit (IROL) under NERC's TOP-007-0 Standard. The standard drafting team created the TOP-007-WECC-1 Standard to limit the amount of time that a SOL may be exceeded for these very important paths, which makes the TOP-007-WECC-1 Standard more stringent than the NERC standard.

NERC COMMENT:

4. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

WECC RESPONSE:

2. The existing standard created confusion during system operation because system conditions may change the limiting conditions on a path. This is because the limit depends upon whether thermal, stability, or post transient limitations are the limiting factor. In addition, having different response times for paths (and sometimes for the same path depending on current outage conditions), complicates system operation, causing delays in responding to the path overload. This resulted in path operators implementing more drastic actions to respond to a contingency within 20 minutes, which may put the system at greater risk, particularly during heavy load periods such as summer. The standard drafting team determined that changing the standard from a 20-minute to a 30-minute response time is insignificant in terms of the probability of a next contingency occurring. Moreover, the drafting team believes that following a system disturbance, the system operators will be better able to identify what generation to ramp in order to be effective in mitigating the overload. This will also allow them to coordinate with others before implementing the generation ramps. Therefore, the simplification of the standard to one consistent 30-minute period improves reliability. It is important to recognize that in spite of extending the recovery period, the refinement should improve system reliability.

VAR-002-WECC-1 — AUTOMATIC VOLTAGE REGULATORS (AVRs)

NERC COMMENT:

4. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-002-WECC-1 Standard clarifies the requirement and “Levels of Non-Compliance” contained in the existing VAR-STD-002a-1 Standard. The 98 percent in Requirement R1. of VAR-002-WECC-1 was contained in the “Levels of Non-Compliance” in the existing VAR-STD-002a-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring the AVR to be in service provides for time to start up generating facilities. It also allows for evaluation when the Generator Operators respond to unforeseen events.

NERC COMMENT (continued):
More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

WECC RESPONSE (continued):
NERC VAR-002-1a R1. permits the Generator Operator to operate in different modes by simply notifying the Transmission Operator. There are no restrictions on the length of time or reasons for operating in other modes. The WECC 1996 outage reports identified the lack of reactive support from generators with AVRs operating in modes other than voltage control as one of the causes of the WECC 1996 outages. The VAR-002-WECC-1 Standard limits the reasons and time for operating a generator without the AVR in service and controlling voltage, therefore it is more stringent than the NERC VAR-002-1a Standard.

NERC COMMENT

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the AVR in service). The use of peaking units adds to overall system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

VAR-501-WECC-1 — POWER SYSTEM STABILIZER (PSS)

NERC COMMENT:

4. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-501-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002b-1 Standard. The 98 percent in Requirement R1. of VAR-501-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002b-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring PSS to be in service provides time for evaluation and to start up generating facilities when Generator Operators respond to unforeseen events.

NERC COMMENT:

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the exiting standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the PSS in-service). Operating at low megawatt levels makes the PSS ineffective. The use of peaking units adds to over-all system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture PSS in service recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes that the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

(NERC) CONCLUSION

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC RESPONSE

WECC appreciates the opportunity to discuss NERC staff's initial evaluation and report in conference calls on August 4 and 5, 2008 and to provide the written clarifications and responses contained herein. We trust that WECC's responses, along with all the supporting documentation contained in WECC's submissions, provide the NERC staff a comprehensive basis for recommending NERC Board of Trustees approval of all proposed standards. Please direct any questions relating to WECC's response to WECC Director of Standards, Steve Rueckert at steve@wecc.biz or (801) 883-6878.

WECC Responses to FERC Staff Concerns and Questions
Regarding the Proposed WECC Tier 1 Standards
June 17, 2008

I. Contingency Reserves – BAL-002-WECC-1

A. Period of Contingency Reserve Restoration: Does the proposed standard modify the current standard to provide a longer period of time of 90 minutes rather than 60 minutes?

Yes, the requirement to restore contingency reserves within 60 minutes was eliminated in the proposed standard. The current standard requires the restoration of contingency reserves within the first 60 minutes following an event. By eliminating this requirement in the proposed standard, WECC adopts the NERC default standard that requires the restoration of contingency reserves within 90 minutes from the end of the disturbance recovery period.[2]

The 60 minute restoration period required by the current standard was developed and used under a manual interchange transaction structure among vertically integrated utilities. As the electric utility industry restructured, there has been a substantial increase in the number of market participants and interchange transactions.[3] To accommodate the increase in number of interchange transactions and market participants an electronic tagging system was implemented in the Western Interconnection. The adoption of an electronic tagging system that accommodates multiple market participants and a large number of interchange transactions made the current mid-hour reserve restoration more cumbersome and made the inappropriate rejection of reserve restoration transactions more likely because such transactions are outside the electronic tagging cycle.

Eliminating the 60 minute reserve restoration requirement and adopting the NERC requirements results in more efficient communication among Balancing Authorities (BAs) because it aligns the restoration of contingency reserves with the electronic tagging system approval cycle. Adopting the NERC contingency reserve restoration requirements reduces the potential for reserve transactions being inappropriately rejected resulting in improved communication among BAs resulting in improved reliability.

B. Shedding of Firm Load: Does the proposed standard change the treatment of the shedding of firm load compared to the current standard?

No, both standards allow for the shedding of firm load under limited circumstances. The addition of requirement R3.4 in the proposed standard clarified the process. During capacity and energy emergencies, a BA or Reserve Sharing Group (RSG) may use load as non-spinning reserves; that is BAs and RSGs will not drop load to maintain their non-spinning reserve requirement. Rather they will use load as part of their non-spinning contingency reserves.

[2] See NERC Standard BAL-002-0 Requirement R6 and WECC Standard BAL-STD-002-0 WR1.d.
[3] Balancing Authorities in the Western Interconnection approve between 2,500 and 4,500 interchange transactions per day.

This standard emphasizes the responsibility of serving customer load first while at the same time protecting the reliability of the Western Interconnection. Even during capacity and energy emergencies, BAs and RSGs are required to comply with the spinning reserve requirements.

C. Deliverability of Contingency Reserves: Does the proposed standard require that contingency reserves be deliverable?

Yes, nothing has changed with respect to the deliverability of contingency reserves.

D. Interruptible Imports: In the current standard the sink BA is required to carry an additional amount of contingency reserves equal to the amount of interruptible imports. Does the proposed standard have the same requirement?

Yes, the term interruptible imports was eliminated from the proposed standard. It was replaced with the added requirement R1.2 which requires that "If the Source BA designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink BA shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s)." This is an improvement from the current standard because it eliminates ambiguity in the term interruptible imports.

E. Demand Side Management: Did the drafting team comply with FERC Order 693 to explicitly allow demand-side management (DSM) to be used for reserves?

Yes, DSM that is deployable within 10 minutes is a subset of interruptible load. Interruptible load is defined in requirement R3.2 as an acceptable type of contingency reserve.

II. Qualified Transfer Path Unscheduled Flow Relief- IRO-006-WECC-1

A. Is the proposed standard intended to address an actual (real time) overload situation?

No, a different standard TOP-007-WECC-1 covers actual (real time) overload situations. The proposed IRO-006-WECC-1 standard includes requirements to reduce schedules, which requires adjustments to generation patterns, to prevent potential overloads during the next operating hour.

B. Should the Unscheduled Flow Mitigation Plan (UFMP) be incorporated in the IRO-006-WECC-1 by reference?

No, the key reliability portions from the UFMP are incorporated in the proposed standard. It is not necessary to reference the remainder of the UFMP.

C. Does the WECC UFMP need to be updated?

Yes, WECC has initiated the process of updating its UFMP.

III. System Operating Limits—TOP-007-WECC-1

A. Could the language in TOP-007-WECC-1 allow for the system to be less than two contingencies away from cascading and more specifically one contingency away from cascading?

No, the proposed standard is designed such that path operations must be at least two contingencies away from cascading during steady state operations. In real time operations when System Operating Limits (SOL) are exceeded for periods not to exceed 30 minutes, there may be system conditions that are less than two contingencies away from cascading.

B. Could IRO-005-2 Requirements R3 and R5 be interpreted that the power system is being operated two contingencies away from a cascading outage while WECC TOP-007-WECC-1 requirement R1 results in the power system being operated one contingency away from a cascading outage?

No, IRO-005-2 requirements R3 and R5 are consistent with the requirements in TOP-007-WECC-1. In the Western Interconnection SOLs are developed in such a manner that the system operation is at least two contingencies away from a cascading failure. This is implicit in the identification of the SOL derivation. If, however, there is a flow that exceeds the SOL, Transmission Operators (TOP) and Reliability Coordinators (RC) must take proactive immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the transmission path exceed the SOL for more than 30 minutes, thus protecting the system from potential cascading for a subsequent contingency.

C. Do SOL changes within the hour extend the time for compliance?

No, SOL changes within an operating hour do not extend the time for compliance.

IV. Automatic Voltage Regulators and Power System Stabilizers – VAR-002-WECC-1 and VAR-501-WECC-1

A. How does VAR-002-WECC-1 coordinate with the new NERC Standard VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules?

VAR-002-WECC-1 contains specific, more restrictive, requirements on generator operators regarding the operation of Automatic Voltage Regulators (AVR) that are not contained in the NERC Standard VAR-002-1. The reasons for these more restrictive requirements are to support transfer capabilities in the Western Interconnection and to address the insufficient supply of reactive power identified as a cause of the 1996 system disturbances in the Western Interconnection. The drafting team designed the VAR-002-WECC-1 Standard to limit the reasons for operating AVRs in a mode that does not control voltage and the amount of time permitted for such operations. Generator operators are still required to comply with all the requirements contained in NERC VAR-002-1.

B. Are Power System Stabilizers (PSS) included in either of these standards?

Yes, VAR-501-WECC-1 contains requirements regarding the in-service operation of PSS.

C. Why were the AVR and PSS replacement period extended to two years from 15 months?

The amount of time to replace AVR and PSS was lengthened to accommodate the approval and procurement time frames for AVR and PSS for nuclear power plants, which are two years.

V. Transmission Maintenance – FAC-501-WECC-1

A. Does the FAC-501-WECC-1 standard reduce the number of lines that are subject to this standard to the SOL limiting factors from the lines and facilities associated with the 40 paths thereby reducing the obligation for maintenance?

No, there is no change in the number of lines or facilities subject to the proposed FAC-501-WECC-1 standard.

Requirement R2 is an accounting/OASIS issue. Why do we care what a schedule is (for pure reliability purposes) as long as the actual flow is handled properly based on the applicable standards? R1 adequately deals with the WECC specific distinction for thermal vs. stability limits. Grant recommends the drafting team delete R2 and M2 from the standard.

Greg Lange
Public Utility District No. 2 of Grant County

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability. R2 is more than an accounting/OASIS issue.

R2, M2 - Net Schedule should be determined/measured solely on a pre-schedule basis and not include any after-the-fact adjustments.

John Appel
Chelan PUD

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour.

R1.2 implies that following a contingency, the flows must be reduced to the new limit of the degraded system (which could be significantly lower) within 20 minutes. Reducing the time requirement from 30 minutes to 20 minutes is not based upon any sound reasoning would create operational strain. Following a system disturbance, the operators may have many other things to worry about. It takes time to figure out which generation ramp down would be effective, coordinate with others, and then it would take some time for the generators to actually ramp down.

Our recommendation would be change time to 30 minutes.

Tom Glock, Baj Agrawal
Arizona Public Service Co.

Reply: The drafting agrees to make the recommended refinement (see revised standard).

While I agree that a transfer path should not be pre-scheduled to a level in excess of its SOL, the primary intent of this reliability standard ought to be focused upon the condition of actual path flows exceeding the SOL. In that regard, the Requirement R2 - when viewed after the fact - is primarily a transaction accounting mechanism, and should not be used to determine if a transfer path was operated reliably. I recommend deletion of both R2 and its associated Measure M2. If it must stay, then re-word it to be applicable to the net interchange that was pre-scheduled rather than ATF.

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

I notice that in proposed R1.1 and R1.2, the familiar terminology of "Thermally Limited Paths" and "Stability Limited Paths" has been replaced by "Facility Ratings or System Voltage Limits" and "Transient Stability Ratings or Voltage Stability Ratings". If this NERC terminology is to be used, I think the Major WECC Transfer Path listing needs to have a column added to reflect which type of rating is applicable for each Path. Today, we can tell if the 20 or 30 minutes applies based on the statements in the Path Rating Catalog, which classify each of the Paths as either Stability limited or thermally limited.

Reply: The drafting team removed the NERC terminology to incorporate other recommended refinements.

With regard to the referenced Table of Major WECC Transfer Paths, I question how it is determined that a particular path gets placed on this list, and how one can be removed. What process exists or will exist to ensure that these paths are the ones truly regarded as "Major?" Of particular concern to me is the continued inclusion of the SPPC-PG&E Path #24, consisting of a pair of 115kV lines and one 60kV line with a rating of barely 100MW in one direction and as little as 10MW in the other. The prominence of this Path and its importance to the Interconnection doesn't even compare to the other facilities that make up this list, such as EOR and COI. In fact, as a testimonial to this Path's insignificance, the phase shifter that fully controls Path 24 was recently disqualified by UFAS as a Qualified Device for unscheduled flow mitigation because of the negligible effect the Cal Sub PST's have today on the WECC Qualified Transfer Paths. While this table may be outside the scope of the Drafting Team, it nonetheless influences my acceptance of this Standard as an issue of applicability.

I appreciate the opportunity to comment on this Standard.

Rich Salgo
Sierra Pacific Resources Transmission

Reply: Reliability Coordinators recommended the original Table of Major WECC Transfer Paths contained in the Reliability Management System Agreement. WECC made refinements to the table through the Reliability Management System amendment process. In the future, any entity may recommend refinements to the table by following the Process for Developing and Approving WECC Standards. For the table WECC Board approval would be required, but NERC and FERC approvals are not required.

Requirement R2 and measure M2 are accounting issues. They should not be included in reliability standard and have no bearing on actual flow or measurement of flow. R1 and M1 are adequate

Net schedule should be measurement solely on a preschedule base and not included in any after the fact adjustment.

Transmission paths have bi-directional SOL's. If schedule power flow is used for measurement purpose, then one must look at the direction and the associated directional SOL solely on a pre-schedule base.

Devinder Ghangass
British Columbia Transmission Corporation

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

BPA agrees with the need to maintain a WECC regional standard that strengthens the NERC requirement of responding to IROL violations within 30 min. By extending the applicability of TOP-007 to SOL violations for specific, critical, WECC paths, the WECC standard improves reliability of the western interconnection.

Remove Requirement R2 and measure M2
When a contingency or other real time operating condition results in path loading over the SOL, System Operators should respond immediately to restore actual flow to below the operating limit. Requirement R1 and Measure M1 address this issue adequately. However, expending the same effort to return net schedules to within the operating limit is not only unnecessary from a reliability point of view, but could be detrimental by interfering with the actions taken in response to the actual flow violation or by placing the system at greater risk during high loading periods.
While BPA acknowledges that net schedules should be less than the path limit on entering the hour, the reality is that a net schedule exceeding the SOL poses little real-time risk to the transmission system and is an equity issue rather than a reliability issue.
Removing R2 and M2 will not affect response time for the real reliability issue, actual flow above SOL, and may improve reliability by allowing System Operators to address actual flow without the added distraction of dealing with a non-reliability accounting problem.
BPA recommends eliminating R2 and M2.
If R2 is retained, the requirement should be modified to consider only net schedules going into the hour. Once in the hour, the major reliability concern is actual flow over the SOL. System Operators should not be distracted from this task to deal with what are essentially equity issues. In addition, the term “net schedules” is vague and should be defined. The definition should be based solely on the pre-schedule, without any after-the-fact adjustment, and if paths are bi-directionally limited, the net schedule should reflect the direction.

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

Change the time limit for stability limited paths to 30 minutes.
The shorter time limit for stability limited paths was originally adopted by WECC to address the perception that a path limited by stability criteria is more likely to result in cascading (should the

next contingency occur) than a path limited by thermal criteria. The reasoning was that you don't have time to respond to a stability problem so your risk is larger with a stability limited path than a thermally limited path where you may have time to manually intervene.

The reduced response time of 20 min for stability limited paths was chosen based on an assumption that reduced response time reduces the probability of incurring the next contingency and therefore the risk of cascading outage.

BPA asserts that the difference between 20 minute and 30 minute response time is insignificant in terms of probability of a next contingency occurring and therefore does not affect the risk the system is exposed to by a next contingency during the response period. Further, having now had several years of experience operating the system to the shorter time frame following a contingency, BPA contends that having different response times for paths (and sometimes for the same path depending on current outage conditions) complicates operation of the system and that the more drastic actions needed to respond to a contingency within 20 minutes may put the system at greater risk, particularly during heavy load periods such as summer.

BPA believes using a consistent 30 minute response time for all SOL violations improves reliability by simplifying procedures for System Operators and providing the additional time necessary for coordinating an orderly response to system trouble.

Reply: The drafting agrees to make the recommended refinement (see revised standard).

Modify R2 to include only scheduled paths in the table.

BPA agrees with the standard drafting team regarding the restriction of applicability of this standard to the paths that have been widely accepted as most significant to the interconnection, as identified by the Major WECC paths table.

BPA strongly supports removing R2 from the standard (see comments above). If R2 is retained, it should only apply to paths with established interchange schedules and not internal paths listed in Attachment 2.

Reply: The drafting team made refinements to R2 to exclude internal paths that are not scheduled.

In addition, BPA suggests that the following changes be made to the list of paths in Attachment 2:

Modify the list of paths to remove BPA internal transfer paths with no schedules. West Of Cascades - North, West of Cascades - South, and North of John Day should be removed because they are not scheduled paths.

BPA also suggests removal of item 40 which refers to the nomogram operation of COI/PDCI and NJD. COI and PDCI are already captured in items 35 and 34, respectively.

Reply: WECC made refinements to the table through the Reliability Management System amendment process. In the future, any entity may recommend refinements to the table by following the Process for Developing and Approving WECC Standards. For the table WECC Board approval would be required, but NERC and FERC approvals are not required.

Brian Tuck
Bonneville Power Administration

Thank you for the opportunity to further comment (see Brian Tuck's earlier comments).

In order to assure awareness of potential problems and time criticality and to assure the RC has the information they need in determining if and when to issue directives, we recommend adding a requirement such as:

The Transmission operator shall identify all stability limited paths and assure that these are known to their System Operators and Reliability Authority.

Donald Watkins
Bonneville Power Administration

Reply: The OTC (SOL) process requires the Transmission Operator to identify the nature of the limit of the path. The drafting team believes this recommendation is not needed with one 30-minute uniform response requirement.

R2

Should this portion of the standard remain, magnitude of over-schedule should be considered in addition to duration of over-schedule when determining the violation severity.

Reply: The drafting team made refinements to the violation severity levels for R2 to include magnitude of schedule.

It seems that deletion of R2 from the standard could lead to gross over-scheduling of transmission paths, which could create overload problems on parallel paths. However, strict adherence to the standard could also be detrimental to the reliability of the transmission system during emergency conditions. The severity index may be a good tool to allow for some degree of over-schedule to compensate for needed transfer capability during some emergency circumstances and still prevent gross manipulation of the transmission system.

Jared Griffiths
Western Area Power Administration-RMR

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

Sacramento Municipal Utility District, System Operations and Reliability recommend removal of R2 and M2 from the proposed standard.

Phillip B. O'Donnell
Sacramento Municipal Utility District

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

Idaho Power would disagree with the removal of R2 but instead believes that the scope of its time frame should end at the "prior to the next hour" real-time scheduling deadline (XX: 40). This would eliminate the possibility of after-the-fact schedule changes creating a violation. Scheduling paths beyond their limit could impact actual flows on parallel paths.
Thank you for your efforts.

Greg Travis
Idaho Power

Reply: The standard drafting team made the recommended refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

Certain words are capitalized within the document (e.g., System Voltage Limit). Please define the term.

Anonymous

Reply: NERC defines the capitalized term used in TOP-007-WECC-1 in its reliability standards (see definition for System Operating Limit).

R.2. and M2. Should be removed because they are accounting measures. Actual power flow should be the measure for SOL violations. NWMT has had experiences when it curtailed all schedules on a path to zero, with no effect on actual power flow. The schedule has nothing to do with the dynamics of the system – regardless of schedules, it is the physical system, including load and generation levels that determine how much and where power will flow. Even the OTCSDT states that it believes net schedules in excess of reliability limits will create "very little reliability risk to the bulk electric system."

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

R1.1. and R1.2. Should be combined, with no differentiation between Facility Rating System Voltage Limits and Transient or Voltage Stability Rating such that a 30 minute limit applies to all SOLs. This supported by OTCSDT who states there is, "no substantial difference between thermally limited and stability limited paths when considering risk to the transmission system…" NWMT has paths that will change from stability limited ratings to thermal limited ratings for specific outages, and the variation in time limits has caused confusion even at the Reliability Coordinator level. With a single time limit for any rating, this confusion is removed.

Reply: The drafting agrees to make the recommended refinement.

Leland McMillian
NorthWestern Energy

Requirements: Clarify that these requirements apply to the paths identified in the tables. As written, it says it applies to the Operators, but doesn't say it applies to only to the major paths.

Scott Peterson
San Diego Gas & Electric

Reply: Section 4 Applicability clearly identifies that the standard only applies to the paths listed in the table.

The CAISO requests consideration of the following comments on the proposed TOP-007-WECC-1:

R2 and M2

The CAISO believes that R2 and M2 should be removed or modified to apply only to the pre-scheduled value for the identified paths.

Reliability requires that actual values be maintained below the SOL on the WECC paths identified. Even if a schedule remained above a SOL mid-hour when the SOL values changed in real-time, as long as the actual flow is below the SOL, there is no reliability issue. Actual flows are the key to maintaining reliability.

If the drafting team elects to keep a version of R2 and M2 in the standard, the requirement and measure should focus on the pre-schedule value, not in hour schedules.

Also, if the drafting team elects to keep a version of R2 and M2 in the final version of this standard, the list of paths that this requirement applies to should be edited to only include those paths that are actually scheduled. The current list includes many paths that are not scheduled paths, so to prove compliance or non-compliance would be impossible.

Reply: The standard drafting team made refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

The paths that are included on the list in the CAISO area but are not scheduled are Path 15, Path 26, & SCIT.

Reply: The drafting team made refinements to R2 to exclude internal paths that are not scheduled.

Anonymous
California Independent System Operator

The Purpose of this standard is to ensure the reliability of the interconnected system by keeping actual flows on the critically defined WECC paths within approved operating limits. Requirement R1 requires the System Operator to take appropriate actions to restore the system to within approved operating conditions in the allotted time frame. The requirement to keep net schedules below operating limits with in the hour does nothing to ensure the reliable operating of the system. Removing R2 and M2 allows the System Operator more time to deal with the important issue at hand, actual flow.

Scott Kinney
Avista Corp.

Reply: The standard drafting team made the recommended refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

The Alberta Electric System Operator (AESO) appreciates the opportunity to comment on the proposed standard and commends the drafting team for the work it has done.

Like many other commenter's, the AESO has concerns regarding R2 and M2 where the net schedule over an interconnection or Path is limited to its SOL. In situations of delivery of emergency energy or contingency reserve, this requirement limits the potential use of the unused portion of the SOL and hence limits the ability of other areas to render assistance to the area that is in needs. This seems to go against the principle of interconnection reliability operation.

The AESO would respectfully ask the drafting team to reconsider this requirement.

Anita Lee, P. Eng.
Manager, Operating Policies and Procedures
Alberta Electric System Operator (AESO)

Reply: The standard drafting team made the recommended refinements to R2 to require Net Scheduled Interchange to be within path limits when the Transmission Operator implements its real-time schedules for the next hour. Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability.

PacifiCorp Energy Commercial & Trading submits the following comments pursuant to WECC's request of September 21, 2007 for comments:

The WECC Standard TOP-007-WECC-1 - System Operating Limits, section R.2. and M2. Require further clarification. The R2. Refers to "net schedule for power flow" and the M2. Refers to "net power flow schedules." We should avoid using the word actual power flow and scheduled in the same definition. It has and will continue to cause ambiguity.

The following modifications would clear this conflict.

Proposed R2.

Transmission Operators shall not have actual power flow over an Interconnection or Transmission Path above the path's SOL for more than 30 minutes.

Proposed M2.

Evidence that actual power flow has not exceeded the SOL for more than 30 minutes as required by R2.

PacifiCorp Trading

Reply: The standard drafting team made refinements to clarify R2 and M2. The drafting team replaced the confusing terms with the NERC defined term "Net Scheduled Interchange."

CONSIDERATION OF COMMENTS FOR TOP-007-WECC-1 – SYSTEM OPERATING LIMITS
COMMENTS WERE DUE JANUARY 2, 2008
JANUARY 24, 2008

The TOP-007-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the WECC TOP-007-WECC-1 Standard. This Standard was posted for a public comment period from November 16, 2007 through January 2, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard by posting comments on the WECC website. There were five sets of comments from five companies.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Steve Rueckert at 801-582-0353 or at steve@wecc.biz. In addition, there is a WECC Appeals Process.

Comments and Responses

B. Requirements

R.2.

"Implements its real-time schedules for the next hour" does not set a definitive time frame. Does implement mean when the schedules go in just before the ramp or does it mean once the ramp is finished? Technically, over-schedules before the ramp period is done may not be in effect and thus may not be adversely impacting any transmission path.

Proposed change:

The Transmission Operator shall not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path's SOL immediately following the end of the WECC ramp period for the hour.

Jared Griffiths
WAPA, RMR

Reply: The requirements for implementing a schedule are covered in NERC Reliability Standards INT-005 thru INT-009. The drafting team made refinements to R2 to permit 30 minutes to adjust Net Scheduled Interchange for a decrease in the SOL.

From: fleblanc@ci.burbank.ca.us

It should at all times be unacceptable to permit net schedules to exceed the System Operating Limit (SOL). For instance, if the California-Oregon Intertie (COI) is de-rated from 4800 MW N-S to 3200

MW at 5 minutes into the operating hour no schedules need to be cut (this assumes that the actual loading is within the new SOL of 3200 MW. What is not contemplated is that additional circuit interruptions or loss of generation can push the loading well above the SOL when through prudent pre-contingency operator action, schedules could have been curtailed to reflect that revised operating limit. The scheduling above the SOL presents a reliability issue that can and must be avoided. Also, the present language does not consider that if the contingency occurs just before schedules are implemented for the next hour there will be a violation because the schedules will be above the new SOL.

This is the present language: "The Transmission Operator shall not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path's SOL when the Transmission Operator implements its real-time schedules for the next hour. For paths internal to a Transmission Operator Area that are not scheduled, this requirement does not apply." [Violation Risk Factor: Low] [Time Horizon: Real-time Operations]

I propose changing it to: "Following a contingency resulting in the transmission path or interconnection being de-rated, the Transmission Operator shall not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path's SOL for more than 30 minutes before ramp initiation. For paths internal to a Transmission Operator Area that are not scheduled, this requirement does not apply." [Violation Risk Factor: Low] [Time Horizon: Real-time Operations]

This change will always permit approximately 30 minutes to revise schedules. It limits exposure to additional events and works no matter when the contingency occurs.

Submitted on behalf of Fred le Blanc, Manager, Energy Control Center, Burbank Water & Power

By Xavier Baldwin, BURB OC member

Reply: The requirements for implementing a schedule are covered in NERC Reliability Standards INT-005 thru INT-009. The drafting team made refinements to R2 to permit 30 minutes to adjust Net Scheduled Interchange for a decrease in the SOL.

NorthWestern Energy is in favor of this standard now that the changes have been made.

Leland McMillan

Reply: Thank you

TOP-007-WECC-1

CAISO comments

The CAISO wishes to thank the drafting team for the improvements made to the WECC standard TOP-007-WECC-1 with this draft. The CAISO asks the standards drafting team to consider the following comments that the CAISO offers to improve the standard.

R2. If a line were to relay or a dynamic SOL limit were to change just prior to schedules being implemented (the ramp), the lack of a grace period could prevent a Transmission Operator from implementing their schedules (starting their ramp) to avoid violation of this requirement. Such a requirement without a grace period would be a detriment to reliability.

Brent Kingsford
California ISO

Reply: Reply: The requirements for implementing a schedule are covered in NERC Reliability Standards INT-005 thru INT-009. The drafting team made refinements to R2 to permit 30 minutes to adjust Net Scheduled Interchange for a decrease in the SOL.

The Alberta Electric System Operator (AESO) appreciates the opportunity to comment and would like to offer the following:

- The AESO is still of the opinion that SOL, by definition, defines how much power can be transferred over a transmission path while meeting system reliability criteria. It is the actual power transfer that should be monitored, not the scheduled power transfer. To apply SOL in a scheduling application does not seem to make sense for the proper application of SOL.

Respectfully,

Anita Lee, P. Eng.
Manager, Operating Policies and Procedures
Alberta Electric System Operator

Reply: Scheduling paths beyond their limits could adversely affect actual flows on parallel paths that may jeopardize system reliability. The requirements for implementing a schedule are covered in NERC Reliability Standards INT-005 thru INT-009. The drafting team made refinements to R2 to permit 30 minutes to adjust Net Scheduled Interchange for a decrease in the SOL.

Drafting Team TOP-STD-007

FIRST NAME	LAST NAME	COMPANY
Shannon	Black	Sacramento Municipal Utility District
Steve	Gillespie	California Independent System Operator
Jared	Griffiths	Westren Area Power Administration WACM
Richard	Hydzik	Avista Corp
Tom	Isham	Arizona Public Service Company
Don	Johnson	PacifiCorp West
Ken	Wilson	Western Electricity Coordinating Council
Brian	Tuck	Bonneville Power Administration
James	Tucker	Deseret Generation & Transmission Cooperative
Gregory	Van Pelt	California Independent System Operator

OPERATING COMMITTEE

TOP-007-WECC-1

SP - State and Provincial
TP - Transmission Provider
TC - Transmission Customer
IS - Interested Stakeholder

Name of Organization	Name of Voting Member	Voting Class	YES	NO	Abstain	
Aquila Networks-WPC (WPE)	Al Logan	TC			X	
Arizona Public Service (AZPS)	David Hansen	TC	X			
Basin Electric Power Cooperative (BEPC)	Becky Kern	TC			X	
Bear Energy LP (BEAR)	Jeff Winkler (alternate)	TC			X	
Bonneville Power Administration-Power Bus Line (BPAP)	Fran Halpin	TC	X			
British Columbia Hydro and Power Authority (BCHA)	Clement Ma	TC	X			
California Department of Water Resources (CDWR)	Glenn Solbert	TC	X			
Calpine Corporation (CALP)	Frank Obertance	TC	X			
Deseret Generation & Transmission Co-op (DGT)	Phil Tice	TC	X			
Dynegy, Inc. (DYN)	Brian Theaker	TC		X		
Eugene Water & Electric Board (EWEB)	Dean Ahlsten	TC	X			
Fortis Energy Marketing & Trading Group (FEMT)	Jay Alexander	TC			X	
Gila River Power, L.P. (PGR)	Kenneth Parker	TC			X	
Great Basin Transmission, LLC (GBT)	Ali Amirali	TC		X		
Idaho Power Company (IPC)	Shaun Jensen	TC			X	
Mirant Americas, Inc. (MIR)	John Stout	TC	X			
Morgan Stanley Capital Group Inc.	Patrick Murray (alternate)	TC	X			
Northern California Power Agency (NCPA)	Fred Young	TC			X	
NRG Power Marketing, Inc. (NRG)	Robert Bailey	TC	X			
Pacific Gas & Electric (PG&E)	Joe Minkstein	TC	X			
PacifiCorp (PACM)	John Apperson	TC	X			
Portland General Electric (PGE)	John Jamieson (alternate)	TC	X			blank
Powerex (PWX)	Mike Goodenough	TC	X			
PPL EnergyPlus, LLC (PPLE)	John Cummings (Alternate)	TC	X			
PPM Energy, Inc. (PPM)	Diana Scholtes (alternate)	TC			X	
Public Service Company of Colorado (PSC)	Steve Buening	TC	X			
Public Service Company of New Mexico (PNM)	David Miller	TC	X			blank
Public Utility District No. 1 of Chelan County (CHPD)	Hugh Owen	TC	X			blank
Public Utility District No. 2 of Grant County (GCPD)	Greg Lange	TC	X			blank
Puget Sound Energy, Inc. (PSE)	Joe Hoerner (alternate)	TC			X	blank
Reliant Energy, Inc. (REI)	Thomas J. Bradish	TC		X		blank
Sacramento Municipal Utility District (SMUD)	Vicken Kasarjian	TC		X		blank
Salt River Project (SRP)	Mike Hummel	TC	X			blank
Seattle City Light (SCL)	Pawel Krupa	TC	X			blank
Sempra Generation (SER)	Leslie Padilla	TC			X	blank
Sierra Pacific Resources Transmission (SPR)	Sheryl Torrey	TC	X			blank
Southern California Edison Company (SCE)	John Pespisa	TC	X			blank
SUEZ Energy Marketing NA, Inc. (SUEZ)	Caitlan Collins	TC	X			blank
SWRTA Class 2 Group (SC2G)	Dennis Delaney	TC			X	blank
Tacoma Power (TPWR)	Catherine Leone-Woods	TC	X			blank
U.S. Bureau of Reclamation (USBR)	Deon Murphy	TC	X			blank
Utility System Efficiencies, Inc.	LeRoy Patterson	TC			X	blank
Western Area Power Administration (WAPA)	Ken Otto	TC	X			blank

Voting Summary	Class	Yes	No	Abstain
	SP	1	0	0
	TC	29	4	13
	TP	30	3	1
total		0	0	0

Board of Directors

April 16-18, 2008 **Voting Summary**

Coronado, CA **TOP-007-WECC-1**

Last Name	First Name	Organization	Class
Anderson	Bob	Non-affiliated Director	Non-Affiliated
Areghini	David	Salt River Project	Class 1
Barbash	Carolyn	Sierra Pacific Power Company	Class 1
Beyer	Lee	California Public Utilities Commission	Class 5
Brown	Duncan	Calpine Corporation	Class 3
Campbell	Ric	Utah Public Service Commission	Class 5
Cauchois	Scott	CADRA	Class 4
Chamberlain	Bill	California Energy Commission	Class 5
Cleary	Anne	Mirant Americas, Inc.	Class 3
Conway	Teresa	Powerex Corp.	Class 6
Coughlin	John	Non-affiliated Board Member	Non-Affiliated
Dearing	Bill	Grant County PUD	Class 2
Ferreira	Richard	TANC Executive Advisor	Class 2
Grantham-Richards	Maude	Farmington Electric Utility System	Class 2
Gutting	Scott	Energy Strategies, LLC	Class 4
Kelly	Nancy	Utah Committee of Consumer Services	Class 4
King	Jack	Non-affiliated Board Member	Non-Affiliated
LaFond	Steve	The Boeing Company	Class 4
Little	Doug	British Columbia Transmission Corporation	Class 6
McMaster	Dale	Alberta Electrical System Operator	Class 6
Moya	Jesus	Comision Federal de Electricidad	Mexico
Newton	Tim	Non-affiliated Director	Non-Affiliated
Sharpless	Jananne	Non Affiliated Board Member	Non-Affiliated
Smith	Marsha	Idaho Public Utilities Commission	Class 5
Stout	John	Mariner Consulting	Class 3
Tarplee	Gary	Southern California Edison	Class 1
Thuston	Tim	Williams Power	Class 3
Weis	Larry	Turlock Irrigation District	Class 2
VanZandt	Vicki	Bonneville Power Administration	Class 1
Zaozirny	Lori Ann	British Columbia Utilities Commission	Class 6

The Board Members listed above voted whether to approve TOP-007-WECC-1. The Regional Reliability Standard was approved unanimiously.

VAR-002-WECC-1 — Automatic Voltage Regulators (AVRs)

Action: VAR-002-WECC-1 — Automatic Voltage Regulators (AVRs) **— Approve**

Proposed Effective Date: On the first day of the first quarter, after applicable regulatory approval.

Summary Conclusion and Recommendation:

- NERC recommends approval of VAR-002-WECC-1 — Automatic Voltage Regulators (AVRs) and associated definition, "Commercial Operation" on the basis that the Regional Reliability Standard is more stringent than the continent-wide NERC Reliability Standard VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules, thus satisfying the statutory criteria for a Regional Reliability Standard.
- The continent-wide NERC Reliability Standard VAR-002-1a requires that a Generator Operator operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator. VAR-002-WECC-1, R1 requires all synchronous generators to have their voltage regulator in service at all times with exceptions only for specified circumstances, making it more stringent than NERC's standard.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

Background*:* WECC-VAR-STD-002a.1 — Automatic Voltage Regulators (AVRs) ensures automatic voltage control equipment on synchronous generators shall be kept in service at all times, with outages coordinated to minimize the number out of service at any one time. All synchronous generators with automatic voltage control equipment shall normally be operated in voltage control mode and set to respond effectively to voltage deviations. Regional Reliability Standard WECC-VAR-STD-002a.1 contains requirements for automatic voltage regulators that exceed those in the continent-wide NERC Reliability Standard, VAR-002-1a, thereby satisfying the statutory criteria for consideration as a Regional Reliability Standard.

In its on June 8, 2007 Order approving eight WECC Regional Reliability Standards, including WECC-VAR-STD-002a.1, FERC directed WECC to make conforming changes to the standard based on the shortcomings identified in NERC's evaluation of the standard, as follows:

1. Remove the sanctions table that is inconsistent with the NERC Sanctions Guidelines and add Violation Risk factors and Violation Severity Levels;
2. Conform the standard to the form of NERC Reliability Standards with respect to the effective date, stating it should become effective on the first day of following quarter upon regulatory approval.

Further, FERC supported NERC's conditions for approval that WECC meet its commitment to address the shortcomings over the course of the year.

Proposal VAR-002-WECC-1 — Automatic Voltage Regulators (AVRs): The proposed Regional Reliability Standard, VAR-002-WECC-1, was submitted to NERC on June 11, 2008, replacing the FERC-approved Regional Reliability Standard WECC-VAR-STD-002a.1. In processing the proposed Regional Reliability Standard, WECC indicated it used its standards development procedure that existed at the time per its Regional Delegation Agreement with NERC.

As with the current FERC-approved WECC-VAR-STD-002a.1, proposed VAR-002-WECC-1 contains requirements for automatic voltage regulators that exceed those in the continent-wide NERC Reliability Standard, VAR-002-1a; thereby satisfying the statutory criteria for consideration as a Regional Reliability Standard. The NERC Reliability Standard VAR-002-1a requires a generator operator operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the generator operator has notified the transmission operator. WECC explains that VAR-002-WECC-1 (R1) requires all synchronous generators to have their voltage regulator in service at all times with exception only for specified circumstances.

The proposed replacement standard, VAR-002-WECC-1, was modified such that it no longer contains the sanctions table; includes Violation Severity Levels, Violation Risk Factors, Measures and Time Horizons; conforms the effective date format to that of the NERC Reliability Standards; and conforms the overall format of the standard to that of the NERC Reliability Standards.

In addition to the directed changes, WECC made other modifications to the standard not included in the FERC and NERC directives:

- WECC proposed a defined term for “Commercial Operation” as follows:

  Commercial Operation — Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.

This term is not in the NERC Glossary of Terms and will be added to the glossary as a WECC-specific definition upon approval of VAR-002-WECC-01.

- WECC modified the standard to include requirements that were previously located in the Measures. Specifically, Measure WM1 of WECC-VAR-STD-002a-1 listed the exceptions to operating with automatic voltage regulators in service. These exceptions were added to R1 of proposed VAR-002-WECC-1 as sub-requirements.
- WECC added R2 to require that Generator Operators and Transmission Operators to have documentation identifying the number of hours excluded for each of the allowed exemptions.
- Lastly, WECC modified the applicability of the standard to include Transmission Operators that operate synchronous condensers. The NERC Reliability Standard VAR-002-1 applies only to Generator Owners and Generator Operators.

NERC 45-Day Posting: Upon WECC board action in April 2008, WECC submitted its seven proposed Regional Reliability Standards to NERC for the required 45-day public posting that took place from April 4–May 20, 2008. The proposed Regional Reliability Standards received two series of comments during the NERC posting, one challenging the ability of qualifying facilities to remain on-line if operating in the desired voltage control mode during periods of voltage decline. WECC supplied NERC with its response to this comment on June 11, 2008, stating that studies of the 1996 WECC blackouts directly support the control mode contemplated in the proposed Regional

Reliability Standard. As a result, WECC did not make conforming changes to the standards from the comments received.

NERC Evaluation: In accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure,* approved by the Regional Reliability Standards Working Group, NERC provided its evaluation of the WECC proposed standard VAR-002-WECC-1 to WECC on July 30, 2008 (Appendix 4). In this report NERC made several recommendations to the proposed standard VAR-002-WECC-1 to which WECC responded in an August 18, 2008 letter (Appendix 5):

- NERC suggested WECC add a table containing the Violation Severity Levels to conform to the NERC Reliability Standards. WECC agreed the proposed Violation Severity Levels in VAR-002-WECC-1 are inconsistent in format with that of the NERC Reliability Standards.
- NERC noted the proposed standard, VAR-002-WECC-1 specified in R1 that AVRs are to be operated in service and controlling voltage 98 percent of all operating hours with the listed exceptions. This appears initially to be different than the current requirement in WECC-VAR-STD-002a-1 which specifies that they are to be in service at all times. WECC clarified in its response to NERC's evaluation (Appendix 5) the requirement had not been modified but rather was a translation of the existing WECC-VAR-STD-002a-1 Levels of Non-compliance into the requirements of VAR-002-WECC-01. The two percent allowance provides for time to start up generating facilities when the AVRs are not yet in voltage control mode. It also allows for evaluation when the Generator Operators respond to unforeseen events.
- NERC also expressed concern that given this 98 percent limitation, the proposed Regional Reliability Standard is no longer more stringent than the continent-wide NERC Reliability Standard VAR-002-1a. WECC explained the NERC VAR-002-1a standard, R1 permits the Generator Operator to operate in different modes by simply notifying the Transmission Operator. There are no restrictions on the length of time or reasons for operating in other modes. The 1996 WECC outage reports identified the lack of reactive support from generators with AVRs operating in modes other than voltage control as one of the causes of the widespread outages. The Regional Reliability Standard VAR-002-WECC-1 limits the reasons and time for operating a generator without the AVR in service and controlling voltage; therefore it is more stringent than the NERC Reliability Standard VAR-002-1a.
- In addition, NERC expressed concern with VAR-002-WECC-1 R1.1 in that the standard excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC explained there is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the AVRs in-service). The exclusion below the five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units without penalty for having an out-of-service AVR per the manufacturer recommendations.

NERC staff believes WECC responded adequately to NERC's suggestions by agreeing to conform the Violation Severity Levels format to that of the NERC Reliability Standards in a revision to the standard. In addition, FERC staff commented on the extension of time proposed in the standard that changes from 15 months to 24 months the time allowed for automatic voltage regulator (AVR) and power system stabilizer replacement. WECC explained that the period of time was lengthened to reflect realistic approval and procurement time frames for this equipment for nuclear power plants in particular.

Supporting Documents:

- Appendix 1 — Regional Reliability Standard Submittal Request
- Appendix 2 — Standard Development Roadmap
- Appendix 3 — Consideration of Comments document on NERC's posting of the regional standard
- Appendix 4 — NERC Evaluation of WECC Regional Standards
- Appendix 5 — WECC Response to NERC Evaluation
- Appendix 6 — WECC Response to FERC Comments
- Appendix 7 — WECC Consideration of Comment Reports
- Appendix 8 — WECC Standards Drafting Team
- Appendix 9 — WECC Balloting

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Regional Reliability Standard Submittal Request

Region: Western Electricity Coordinating Council

Regional Standard Number: VAR-002-WECC-1

Regional Standard Title: Automatic Voltage Regulators

Date Submitted: June 10, 2008

Regional Contact Name: Steven L. Rueckert

Regional Contact Title: Director of Standards

Regional Contact Telephone Number: (801) 582-0353

Request (check all that apply):

- ☒ Approval of a new standard
- ☐ Revision of an existing standard
- ☒ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

- ☒ Yes April 16, 2008
- ☐ No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:

The purpose of this standard is to create a permanent replacement standard for VAR-STD-002a-1. VAR-002-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when VAR-STD-002a-1 was approved as a NERC reliability standard.

Concise statement of the justification of the request:

The VAR-002-WECC-1 Regional Reliability Standard is more stringent than the continent-wide reliability standard (Standard VAR-002-1a — Generator Operation for Maintaining Network

To page 1 resource links

Voltage Schedules). In the Western Interconnection, System Operating Limits for transmission paths in the Bulk Electric System assume that Automatic Voltage Regulators are in service to control voltage to support the transfer capability. A requirement for generator operators to keep Automatic Voltage Regulators in service control voltage was instituted after a 1996 disturbance, which was caused by insufficient supply of reactive power from generators, including automatic voltage regulators that were not operating in voltage control mode. As a result of this experience, WECC determined that there should be only very limited circumstances where a generator should remove its unit from AVR operation. The requirements in VAR-002-WECC-1 are to ensure that the generator provides the proper voltage support when generation and transmission outages occur. Therefore in the Western Interconnection, Automatic Voltage Regulators are only permitted to be out of service (not in voltage control mode) under very specific predefined conditions. The NERC VAR-002-1a only requires that a generator operator notify its transmission operator when it either removes or operates the automatic voltage regulator in a condition other than voltage control mode and does not limit the amount of time for such operations.

Other — please attach or include as separate files:

- The text of the Regional Reliability Standard in MS Word format that:
  - has either been, or is anticipated to be, approved by the regional entity's board, and
  - is in a format consistent with the NERC template for reliability standards.
- An implementation plan.
- The regional entity standard drafting team roster.
- The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.
- The final ballot results, including a list of significant minority issues that were not resolved, and
- For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

Completed Actions	Completion Date
1. Post Draft Standard for initial industry comments	September 26, 2007
2. Drafting Team to review and respond to initial industry comments	November 30, 2007
3. Post second Draft Standard for industry comments	November 30, 2007
4. Drafting Team to review and respond to industry comments	January 25, 2008
5. Post Draft Standard for Operating Committee approval	January 25, 2008
6. Operating Committee approved proposed standard	March 6, 2008
7. Post Draft Standard for WECC Board approval	March 12, 2008
8. Post Draft Standard for NERC comment period	April 14, 2008
9. WECC Board approved proposed standard	April 16, 2008
10. NERC comment period ended	May 20, 2008
11. Drafting Team completes review and consideration of industry comments to NERC posting	May 30, 2008

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for VAR-STD-002a-1. VAR-002-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when VAR-STD-002a-1 was approved as a NERC reliability standard.

In the Western Interconnection, System Operating Limits for transmission paths in the Bulk Electric System assume that Automatic Voltage Regulators are in service to control voltage to support the transfer capability. The requirements in VAR-002-WECC-1 are to ensure that the generator provides the proper voltage support when generation and transmission outages occur.

This version of the VAR-002-WECC-1 standard is for NERC Board of Trustee ballot. The WECC Board of Directors approved the standard April 16, 2008. WECC Operating Committee approved the standard March 6, 2008. The WECC Board of Directors and Operating Committee request that the NERC Board of Trustees approve the VAR-002-WECC-1 Standard as a permanent replacement standard for VAR-STD-002a-1 and that the NERC Board of Trustees submits the standard to FERC for approval and replacement of VAR-STD-002a-1.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit NERC Board approval request	June 2008
2. Request FERC approval	June 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

Commercial Operation - Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.

A. Introduction

1. Title: **Automatic Voltage Regulators (AVR)**

2. Number: VAR-002-WECC-1

3. Purpose: To ensure that Automatic Voltage Regulators on synchronous generators and condensers shall be kept in service and controlling voltage.

4. Applicability

4.1. Generator Operators

4.2. Transmission Operators that operate synchronous condensers

4.3. This VAR-002-WECC-1 Standard only applies to synchronous generators and synchronous condensers that are connected to the Bulk Electric System.

5. Effective Date: On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall have AVR in service and in automatic voltage control mode 98% of all operating hours for synchronous generators or synchronous condensers. Generator Operators and Transmission Operators may exclude hours for R1.1 through R1.10 to achieve the 98% requirement. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R1.1. The synchronous generator or synchronous condenser operates for less than five percent of all hours during any calendar quarter.

R1.2. Performing maintenance and testing up to a maximum of seven calendar days per calendar quarter.

R1.3. AVR exhibits instability due to abnormal system configuration.

R1.4. Due to component failure, the AVR may be out of service up to 60 consecutive days for repair per incident.

R1.5. Due to a component failure, the AVR may be out of service up to one year provided the Generator Operator or Transmission Operator submits documentation identifying the need for time to obtain replacement parts and if required to schedule an outage.

R1.6. Due to a component failure, the AVR may be out of service up to 24 months provided the Generator Operator or Transmission Operator submits documentation identifying the need for time for excitation system replacement (replace the AVR, limiters, and controls but not necessarily the power source and power bridge) and to schedule an outage.

R1.7. The synchronous generator or synchronous condenser has not achieved Commercial Operation.

R1.8. The Transmission Operator directs the Generator Operator to operate the synchronous generator, and the AVR is unavailable for service.

R1.9. The Reliability Coordinator directs Transmission Operator to operate the synchronous condenser, and the AVR is unavailable for service.

R1.10. If AVR exhibits instability due to operation of a Load Tap Changer (LTC) transformer in the area, the Transmission Operator may authorize the Generator Operator to operate the excitation system in modes other than automatic voltage control until the system configuration changes.

R2. Generator Operators and Transmission Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.10. *[Violation Risk Factor: Low] [Time Horizon: Operations Assessment]*

C. Measures

M1. Generator Operators and Transmission Operators shall provide quarterly reports to the compliance monitor and have evidence for each synchronous generator and synchronous condenser of the following:

R1.1. The actual number of hours the synchronous generator or synchronous condenser was on line.

R1.2. The actual number of hours the AVR was out of service.

R1.3. The AVR in service percentage.

R1.4. If excluding AVR out of service hours as allowed in R1.1 through R1.10, provide:

R1.4.1. The number of hours excluded, and
R1.4.2. The adjusted AVR in-service percentage.

M2. If excluding hours for R1.1 through R1.10, provide the date of the outage, the number of hours out of service, and supporting documentation for each requirement that applies.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be a calendar quarter.

1.3 Data Retention

The Generator Operators and Transmission Operators shall keep evidence for Measures M1 and M2 for three years plus current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

1.4.1 The sanctions shall be assessed on a calendar quarter basis.

1.4.2 If any of R1.2 through R1.9 continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. For example, in R1.4 if the 60 day repair period goes beyond the end of a quarter, the repair period does not reset at the beginning of the next quarter.

1.4.3 When calculating the in-service percentages, do not include the time the AVR is out of service due to R1.1 through R1.10.

1.4.4 The standard shall be applied on a machine-by-machine basis (a Generator

Operator or Transmission Operator can be subject to a separate sanction for each non-compliant synchronous generator and synchronous condenser).

2. Violation Severity Levels for R1

2.1. Lower: There shall be a Lower Level of non-compliance if the following condition exists:

2.1.1. AVR is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.2. Moderate: There shall be a Moderate Level of non-compliance if the following condition exists:

2.2.1. AVR is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.3. High: There shall be a High Level of non-compliance if the following condition exists:

2.3.1. AVR is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.4. Severe: There shall be a Severe Level of non-compliance if the following condition exists:

2.4.1. AVR is in service less than 70% of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

3. Violation Severity Levels for R2

3.1. Lower: There shall be a Lower Level of non-compliance if documentation is incomplete with any requirement R1.1 through R1.10.

3.2. Moderate: There shall be a Moderate Level of non-compliance if the Generator Operator does not have documentation to demonstrate compliance with any requirement R1.1 through R1.10.

3.3. High: Not Applicable

3.4. Severe: Not Applicable

E. Regional Differences

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002a-1	

Appendix 3

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Report Form for WECC Standard VAR-002-WECC-1 — Automatic Voltage Regulators

The VAR-002-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the VAR-002-WECC-1 Standard. This Standard was posted for a 45-day public comment period from April 4, 2008 through May 20, 2008. NERC distributed the notice for this posting on April 7, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were three sets of comments from five companies representing four of the ten Industry Segments as shown in the table on the following pages.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the Standard can be viewed in their original format at:

http://www.nerc.com/~filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Manager of Regional Standards, Stephanie Monzon at Stephanie.monzon@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is described in the NERC Regional Reliability Standards Development Procedure: ftp://www.nerc.com/pub/sys/all_updl/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Scott A. Etnoyer	Constellation Power Generation					✓					
2.	Annette Bannon, Tom Olson, and Gus Wilkins	PPL Generation, LLC, PPL Montana, LLC					✓	✓				
3.	Denise Koehn Jack Allison	Bonneville Power Federal Hydro Projects	✓		✓		✓	✓				

Index to Questions, Comments, and Responses

1. **Was the WECC Standard VAR-501-WECC-1 – Power System Stabilizer developed in a fair and open process, using the Process for Developing and Approving WECC Standards?**

Summary Consideration:

Commenter	Yes	No	Comment
Scott A. Etnoyer		X	Concerns of merchant QF generators provided in written comments to WECC have not been addressed in the drafting of this standard. Constellation Energy (CE) opposes WECC's request that VAR-002-WECC-1 be approved as a Regional Standard. CE commends WECC for its efforts to improve reliability and is pleased to have actively participated and provided comments to WECC in this regional Standard development process. However, in this case, CE believes that the WECC Standards development process to date has not adequately addressed concerns raised during VAR-002-WECC-1's review and approval. WECC advanced this standard through its regional commenting process, but the final proposed standard now submitted to NERC does not resolve concerns raised by generation stakeholders, including CE, in this region. Specifically, generation stakeholders believe implementing the standard with respect to small generators would result in loss of generation rather than enhanced reliability at times when the system is in need. As a result, CE believes this proposed standard has serious substantive flaws that, although raised by stakeholders in filed comments, were not addressed during the editing and approval process. **CE believes that NERC must reject the proposed standard and remand it to WECC for further discussion.** As currently written, this Standard does not advance regional reliability (a necessary criterion to create a regional standard), but actually reduces regional reliability. This alone should cause NERC to take a close look at this standard before passing it on to FERC. The Standard would require small merchant QF generation facilities to do something they operationally are unable to do – sustain grid voltage during a degrading condition. The reality is that small generators are far more likely to trip off-line during a negatively trending system voltage if they are forced to operate in Auto Volt Control mode, thus reducing reliability. However, should this standard be approved, it might lead system planners to adopt false assumptions regarding how small generators would perform during voltage declines and thus provide a false margin of modeled security. The standards development process did not address this concern.

Commenter	Yes	No	Comment
			This fundamental and serious flaw in the proposed standard is a product of defects in the WECC Standards Approval Process. Collectively, members of the merchant generation community have little voting power in the Standards Approval Process of the Operating Committee under the current governance structure. When WECC advances Standards that contain serious flaws, such as this one, this stakeholder segment has too little voting power to influence the voting body to make necessary corrections. Generators are unable to influence outcomes unless they obtain agreement from the more powerful voting block – transmission owners/operators, which at times have competing interests. More specifically to this particular proposed standard, WECC did not adequately address issues raised in a request for interpretation of NERC Standard VAR-002-1 dated January 24, 2007 and the NERC response issued on March 5, 2007 [see attached .pdf document]{the .pdf document is included below as part of this comment}, which makes queries regarding AVR operation and allowances for deviation from that requirement. Nor has WECC adequately addressed the meaning of that interpretation in response to comments made by stakeholders with regard to implementing that interpretation in VAR-002-WECC-1. Also, WECC dismissed issues raised by CE's consultant (Roger Robinson – see below) regarding Qualified Facilities connected to the Bulk Electric System (BES) under CPUC Rule 21. WECC's response was factually incorrect in that Rule 21 was indeed the basis for CE's QF's connecting to the BES. *"Many Qualified Facilities (QF) in California were connected to the BES under the California Public Utility Commission (CPUC) Rule 21. Some Utilities in their interpretation of Rule 21 required the QF to operate the AVR in Power Factor (pf) mode as a condition of the Interconnection Agreement (ICA) and Power Purchase Agreement (PPA). Requiring the QF to now operate in the AVR in automatic, controlling voltage, puts operation of these plants in conflict with the criteria used for the Reliability, Safety, and Stability Studies of the BES that were completed by the Transmission Operator (TOP) at the time of the interconnection. Operating in the voltage control mode also puts the QF in conflict with the contractual conditions with the TOP currently in force.* *The above is in conformance with NERC Standard VAR-002 and the current NERC*

Commenter	Yes	No	Comment
			interpretation of that standard as referenced in WECC-VAR-STD-002a. The relief given in the draft VAR-002-WECC-1 R1.10 only temporarily deals with the specific instability due to a LTC in the area and does not address the above issues. *The PPAs for QFs requires them to pay for VARs taken and not be paid for VARs given to the grid. Operating in the voltage control mode with the set point, as directed by the TOP, does not allow the QF any control over the movement of VARs to and from the BES and can be a severe financial hardship.* *Roger Robinson* *rmc@att.net* *Reply: CPUC Rule 21 only applies to generators on distribution systems. This standard applies to synchronous generators and condensers that are connected to the Bulk Electric System. "* The operational consequences of WECC's non-responsiveness to comments and adoption of VAR-002-WECC-1 are effectively summarized in the March 20, 2008 comments posted by John Stout, Mariner Consulting Services, on the WECC website in response to the Operating Committee approval of VAR-002-WECC-1: *"At the March OC meeting, a significant number of WECC Generation Operators voted against acceptance of the proposed WECC AVR standard. Most did so because this standard allows Transmission Operators to direct generators to operate in a manner which exposes WECC to a significant and unnecessary risk of voltage collapse, and exposes those generators to increased and unreasonable risk of incurring non-compliance penalties.* *One of the important lessons learned in the July/August 1996 WECC blackouts was that operation of generation in a constant reactive power mode increased the risk of voltage collapse and, therefore, should be limited in WECC. The technical reason for this conclusion is the fact that when voltage begins to collapse, increased reactive power output is required in order to raise the voltage and prevent it from collapsing to the point of causing a blackout. Therefore, WECC established a requirement that, with ten exceptions, generation controls had to be operated in the constant voltage mode of operation. In this mode of operation, if voltage declines, the generator automatically*

Commenter	Yes	No	Comment
			increases and maintains its reactive power output until the voltage returns to normal. That requirement is the genesis of the proposed WECC AVR standard. *WECC Generation Operators support the requirement that their AVR's be operated to maintain voltage and automatically respond with increased reactive output to prevent voltage collapse.* *However, not all WECC Transmission Operators allow interconnected Generation Operators to provide voltage responsive reactive support. Certain Transmission Operators have refused to provide voltage schedules to their Generation Operators. They are allowed to do this because the proposed WECC AVR standard does not include a requirement that Transmission Operators provide voltage schedules. Instead, the WECC AVR standard is silent on this issue, allowing Transmission Operators to follow less restrictive NERC standards which afford them the option of providing reactive power schedules rather than voltage schedules. This practice forces Generation Operators to manually adjust their AVR voltage setting by trial and error to find a voltage setting that will provide the exact amount of reactive power directed by the Transmission Operator. Since the voltage on the transmission grid varies throughout the day, the Generation Operator is forced to continuously reset the voltage on the AVR. This is an unnecessary and distracting manual control burden on the Generation Operator. It effectively eliminates the "Automatic" in "Automatic Voltage Regulator."* *NERC VAR-002 requires the Generation Operator to comply exactly with the voltage schedule or reactive power schedule directed by the Transmission Operator. If the Transmission Operator provides a voltage schedule, the AVR can automatically maintain compliance with the NERC standard. If the Transmission Operator refuses to provide a voltage schedule, and instead insists on providing a reactive power schedule, compliance can no longer depend on the automatic operation of the AVR. The proposed WECC AVR standard prohibits the AVR from being switched to a constant reactive power mode of operation. Instead compliance becomes totally dependent on constant attention and readjustment by the Generation Operator. This significantly increases the risk of reliability standard non-compliance for the generator.* *Even more disturbing is the fact that this situation (the Transmission Operator specifying a constant reactive power output rather than a constant voltage level) defeats the intended purpose of the WECC AVR standard, to prevent a voltage collapse. If voltage does begin to collapse, the generator AVR, operating in constant voltage mode, will increase the reactive power output from the unit. That increase in reactive output means that the generator will no longer be producing the amount of reactive power specified by the Transmission Operator's reactive power schedule. Once this occurs, the Generation Operator must immediately reduce the reactive power provided by the generator or*

Commenter	Yes	No	Comment
			risk fines for noncompliance with NERC standard VAR-002, R2. That will result in the generator doing the exact opposite of what is needed to prevent a voltage collapse and exposes WECC to a risk of blackout. *This issue was repeatedly raised during the standards development process, but the drafting team took the position that it was not a problem that needed to be addressed by the WECC AVR standard. During the March vote at the OC, an amendment was proposed to resolve this issue by adding a requirement to the WECC AVR standard that Transmission Operators provide voltage schedules instead of reactive power schedules. No one expressed an opinion that the concerns raised by generators regarding the reliability risk to WECC were invalid, yet the proposed solution was overwhelmingly rejected by the OC. Unfortunately, due to the voting structure of the OC, the concerned Generation Operators are in a minority and could do nothing more to resolve this issue.* *The WECC Board should not take the same path as did the drafting team and the Operating Committee. We believe the Board should do at least three things before approving this standard.* *First, the WECC Board should ask the OC to report on the validity of the reliability risk and the compliance risk described above. If their response results in a Board conclusion that either risk if valid, the following additional questions should be should be raised by the Board.* *The WECC Board should ask the OC to provide specific information on which Transmission Operators provide reactive power schedules rather than voltage schedules to their interconnected generators. This information should include the specific reasons why such Transmission Operator's have chosen to provide reactive power schedules and explain why those reasons outweigh the reliability and compliance risk created by reactive power schedules. If the Board concludes those reasons are not sufficiently justified, the Board should remand this AVR standard for inclusion of a voltage schedule requirement.* *If valid reasons are provided to the preceding question, the WECC Board should ask the OC to explain why each of those reasons were not included with the ten exceptions already listed under R1 of the WECC AVR standard. If the OC cannot justify why those reasons should not be included in the ten exceptions, the Board should remand the standard until those reasons are included. By adding such reasons to the list of exceptions, Generation Operators should be allowed to place their AVR in the automatic control mode that matches the reactive power schedule provided by the Transmission Operator (i.e. Constant MVAR mode for VAR Schedules or constant Power Factor mode for Power Factor Schedules.)*

Commenter	Yes	No	Comment
			While Board members may feel a reluctance to not support the OC recommendation to approve the currently proposed AVR standard, each Board member should recognize an important distinction between votes at the OC and votes by the Board. Standing Committee members are entitled to vote in accordance with their self interests. Board members have a different standard. Board Members are obligated to vote what is best for WECC. That difference can cause Board votes to sometimes result in different outcomes than Standing Committee votes. While our position was the minority opinion within the OC, we firmly believe it to be the best path for maintaining the reliability and credibility of WECC." For the reasons discussed above, CE requests that NERC reject this proposed standard and remand it to WECC for further discussion and resolution of the issues identified herein amongst the stakeholders. Scott Etnoyer Manager – CPG NERC Compliance (410)470-2661 **Request for Interpretation of NERC Standard VAR-002-1** **Dated January 24, 2007** **John H. Stout** **Mariner Consulting Services, Inc.** **1303 Lake Way Drive** **Taylor Lake Village, Texas 77586** Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator. Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

Commenter	Yes	No	Comment
			The two underlined phrases are the reasons for this interpretation request. Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar. In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows: • The AVR is clearly in service because it is operating in one of its operating modes • The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage • R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage. Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur. The material impact of misinterpretation of these standards is twofold. • First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse. • Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard. In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

Commenter	Yes	No	Comment
			• First, does AVR operation in the constant PF or constant Mvar modes comply with R1? • Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode? **Interpretation of NERC Standard VAR-002-1** **Prepared by Phase 3&4 Standard Drafting Team Members** **Dated March 5, 2007** **In response to February 2007 request from** **John H. Stout** **Mariner Consulting Services, Inc.** **1303 Lake Way Drive** **Taylor Lake Village, Texas 77586** **Questions and Answers** The answers to the two questions posed by Mr. John H. Stout are: 1. Question: First, does AVR operation in the constant PF or constant Mvar modes comply with R1? Answer: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage. 2. Question: Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode? Answer: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed. **Background and Discussion**

Commenter	Yes	No	Comment
			Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator. Requirement R1 clearly states controlling voltage. This can only be accomplished by using the automatic voltage control mode. Using the Power Factor (PF) or constant MVAR control is not a true method to control voltage even though they may have some effect on voltage. This is the baseline mode of operation that is clearly conditioned by "unless the Generator Operator has notified the Transmission Operator". The following Requirement R2 introduces the possibility of an exemption to this baseline mode of operation discussed below. The above interpretation is further reinforced by reviewing the origin of the requirement. The current Requirement R1 is an evolution of the words in the associated source document, namely NERC Planning Standards Compliance Template for III.C.M1, "Operation of all synchronous generators in the automatic voltage control mode". As stated in the original III.C.S1 Standard: **"All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the transmission system operator."** Requirement R2 of Standard VAR-002-1 goes on to state that "Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator." The purpose of this requirement is to give the Transmission Operator the ability to direct the Generator Operator to use another mode of operation. This ability may be necessary based on the Transmission Operator's system studies and/or knowledge of system conditions. This ability also gives the Transmission Operator the latitude to work with the Generator Operator who has a generating unit that lacks the physical equipment to be able to run in the automatic voltage control mode or has contractual requirements to operate in a certain manner. Both Requirements R1 and R2 in VAR-002-1 were worded such that they coordinate with

Commenter	Yes	No	Comment
			Requirement R4 in VAR-001-1: "Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage). " Again this Requirement R4 reflects that the baseline mode of operation is to use the automatic voltage control mode with the option for the Transmission Operator to specify other modes of operation as dictated by system studies and needs to maintain system reliability.
Response: The drafting team disagrees with the commenter's fundamental premise that operation of generator automatic voltage regulators (AVR) in any mode other than voltage control is acceptable for synchronous machines connected to the Bulk Electric System (BES). Due to reliability concerns, WECC has a long history recommending and requiring that generation connected to the BES operate the generator automatic voltage regulators in voltage control mode. These recommendations were validated in 1996 when insufficient control of reactive power resulted in a major disturbance in the West. Subsequent identification of numerous synchronous machines operating the generator AVR in constant power factor mode and other deficiencies resulted in the development of the Reliability Management System, which contractually obligated machine owners to only operate the generator AVRs in voltage control mode. The drafting team further disagrees that implementing the standard will result in the loss of generation. When the automatic voltage regulators are operated in voltage control mode (controlling voltage), generators will provide additional reactive power to support the system when actual system voltage declines. The additional reactive power support is necessary to enhance BES reliability during system events. The amount of reactive support provided depends on the generator's reactive support capabilities and the voltage schedule. When automatic voltage regulators are properly tuned, there is no reduction in power production. However, the amount of reactive power provided is limited by the amount of generation. The need for this reactive power response has been demonstrated through technical studies and many years of experience. The commenter did not present any evidence to demonstrate that smaller generators respond differently than larger generators. Therefore, the drafting team does not believe there are serious flaws with the standard. The development and balloting of the VAR-002-WECC-1 Standard was conducted in accordance with the Bylaws of the Western Electric Coordinating Council revised July 27, 2007 and WECC Regional Delegation Agreement. FERC found that WECC's standard development process and balloting of reliability standards to be fair and open. All industry stakeholders were permitted to participate in the VAR-002-WECC-1 standard development and in the ballot. All industry segments were permitted to participate when a ballot was conducted at the March 6, 2008 Operating Committee meeting. In addition, all industry stakeholders are fairly represented on the WECC Board of Directors, which ensures that the interests of all industry stakeholders and industry sectors are heard and represented fairly. Transmission owners and operators did not inappropriately influence the development of the standard. The ballot results at the Operating Committee and the WECC Board of Directors indicate that many generator owners and operators supported the VAR-002-WECC-1 standard. At the Operating Committee, the vote was in favor of the standard when transmission providers (the transmission owner and operator voting block) were			

Commenter	Yes	No	Comment
excluded. The ballot results for transmission customers that include generator owners and operators were 25 yes, 11 no, and 11 abstained. The WECC Board of Directors contains seven classes of membership including class 3 that represents independent power producers. The Board of Director ballot was 24 yes, 4 no, and 2 abstained. The drafting team, in accordance with the standard request and its responsibility to protect the reliability of the BES, designed the VAR-002-WECC-1 Standard to contain specific more restrictive criteria not contained in the NERC VAR-002-1 Reliability Standard. The WECC VAR-002-WECC-1 Reliability Standard is designed to limit the reasons for not operating automatic voltage regulators in voltage control mode and the amount of time generators may be operated in different modes. Therefore, the commenter is correct the WECC VAR-002-WECC-1 Standard restricts the amount of time that generators are permitted to be operated when automatic voltage regulators are not controlling voltage. The reason for these more restrictive requirements is to support transfer capabilities and to address the insufficient supply of reactive power, which was identified as a cause of a 1996 system disturbance. The existence of the claimed conflict is also questionable. Assuming there is a conflict, the VAR-002-WECC-1 standard applies to electric generation resources connected at voltages of 100 kV or higher, generally, as noted in the NERC definition and applicability Section A.4.3 of the standard. Where as, Rule 21 applies to generators interconnected to the distribution system generally at voltages 60 kV and below. It is, however, possible for generator operators to operate AVRs to comply with both requirements, that is at the same time operate to control voltage and operate within a range of reactive power limits. This may be more difficult, but is still possible and will add to the reliability of the Bulk Electric System. Finally, Rule 21 appears to address commercial interconnection issues unrelated to the reliability of the Bulk Electric System. The standard drafting team believes that it adequately considered the commenter's concerns and the concerns of merchant QF generators provided as written comments to the drafting of this standard The standard drafting team recognizes that in order to development a standard that enhances the reliability of the BES, the team did not implement the commenter's recommendations.			
Annette Bannon, Tom Olson, and Gus Wilkins			
Response:			
Denise Koehn Jack Allison	X		
Response: Thank you.			
Response:			

2. **Does the WECC Standard VAR-501-WECC-1 – Power System Stabilizer pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Commenter	Yes	No	Comment
Scott A. Etnoyer	X		Smaller QF generators are being asked to perform during a potential voltage decline in a manner they operationally cannot, hence creating a false set of modeled assumptions on real-time conditions that will take place at a very critical period on the bulk electric system. See also comments on Question 1.
Response: The drafting team disagrees that implementing the standard will result in the requirement of generators operating in a manner that they operationally cannot. When the automatic voltage regulators are operated in voltage control mode (controlling voltage), generators will provide additional reactive power to support the system when actual system voltage declines. The additional reactive power support is necessary to enhance BES reliability during system events. The amount of reactive support provided depends on the generator's reactive support capabilities and the voltage schedule. The need for this reactive power response has been demonstrated through technical studies and many years of experience. The commenter did not present any evidence to demonstrate that smaller generators respond differently than larger generators and cannot operate to control voltage.			
Annette Bannon, Tom Olson, and Gus Wilkins			
Response:			
Denise Koehn Jack Allison		X	
Response: Thank you.			
Response:			

3. Does the WECC Standard VAR-501-WECC-1 – Power System Stabilizer pose a serious and substantial threat to public health, safety, welfare, or national security?

Summary Consideration:

Commenter	Yes	No	Comment
Scott A. Etnoyer		X	Smaller QFS are only one contributor to voltage support on the WECC grid. The performance concern identified here has a significant negative impact on the QF generator and could potentially be harmful to grid reliability, it is not predictable whether this standard would pose substantial threat to public health, safety and welfare or national security.
Response: The drafting team recognizes that a single smaller Qualified Facility (QF) only provides a limited amount of voltage support. But many smaller QFs working jointly to provide reactive support have a positive effect on system voltage during system events. Additional reactive power support is necessary to enhance BES reliability during system events. The amount of reactive support provided depends on the generators' reactive support capabilities and the voltage schedule. The need for this reactive power response has been demonstrated through technical studies and many years of experience. Enhanced system reliability will not impose a substantial threat to public health, safety and welfare, or national security.			
Annette Bannon, Tom Olson, and			

Commenter	Yes	No	Comment
Gus Wilkins			
Response:			
Denise Koehn Jack Allison		X	
Response: Thank you.			
Response:			

4. **Does the WECC Standard VAR-501-WECC-1 – Power System Stabilizer pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

Summary Consideration:

Commenter	Yes	No	Comment
Scott A. Etnoyer		X	
Response: Thank you.			
Annette Bannon, Tom Olson, and Gus Wilkins	X		The proposed standard does not have a grandfathering provision to address existing, older generating units that may not meet the proposed requirement. Also, this standard does not give the generator operator the option to operate in manual voltage setpoint mode.
Response: The drafting team did not identify a need to permit a grandfather provision for the automatic voltage regulator standard. The NERC VAR-002-1 standard does not have a provision that provides an exception due to age. Automatic voltage regulators are not new devises. WECC, through its RMS program, has required the operation of synchronous generators in voltage control mode since 1999. Additional reactive power support is necessary to enhance BES reliability during system events. The amount of reactive support provided depends on the generator's reactive support capabilities and the voltage schedule. The drafting team did not identify a specific need to permit the operation in manual voltage setpoint mode for extended periods of time. The commenter did not demonstrate that operation in manual voltage setpoint is necessary for reliability.			
Denise Koehn Jack Allison		X	
Response: Thank you.			
Response:			

5. **Does the WECC Standard VAR-501-WECC-1 – Power System Stabilizer meet at least one of the following criteria?**

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Commenter	Yes	No	Comment
Scott A. Etnoyer			
Response:			
Annette Bannon, Tom Olson, and Gus Wilkins			
Response:			
Denise Koehn Jack Allison	X		
Response: Thank you.			
Response:			

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Appendix 4

NERC Evaluation of Western Electricity Coordinating Council (WECC) Regional Standards

Executive Summary
July 30, 2008

On June 11, 2007, the WECC submitted the following seven regional standards for NERC evaluation to replace eight original WECC regional standards approved by NERC and FERC in 2007:

- BAL-002-WECC-1 — Contingency Reserves,
- FAC-501-WECC-1 — Transmission Maintenance,
- IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief,
- PRC-004-WECC-1— Protection System and Remedial Action Scheme Misoperation,
- TOP-007-WECC-1 — System Operating Limits,
- VAR-002-WECC-1 — Automatic Voltage Regulators and
- VAR-501-WECC-1 — Power System Stabilizer

NERC posted these seven proposed regional standards for a 45-day public posting beginning April 4–May 20, 2008. The standards received several comments during the NERC public posting. WECC supplied NERC with its responses to the comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting. WECC submitted these standards for NERC evaluation on June 11, 2008.

In accordance with NERC's *Rules of Procedure* and the *Regional Reliability Standards Evaluation Procedure* approved by the Regional Reliability Standards Working Group, NERC performed a review of the WECC proposed standards. The intent of this document is to provide WECC with NERC's feedback regarding their regional standards.

In this review, NERC presents a summary of observations for each proposed WECC regional standard. In Appendix A, NERC includes a redlined copy of each proposed regional standard with detailed comments included. NERC believes WECC has satisfied its procedural obligations as outlined in Appendix C of its Regional Delegation Agreement. However, NERC offers concerns and suggestions regarding several of the proposed regional standards that are discussed below.

Summary of Findings

BAL-002-WECC-1 — Contingency Reserves

In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

1. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

2. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

   R2. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

   R2.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

   R2.2. Capable of fully responding within ten minutes.

   In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

3. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

4. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

FAC-501-WECC-1 — Transmission Maintenance

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

1. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

2. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

1. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

2. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

3. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

1. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

2. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

3. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

4. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

TOP-007-WECC-1 — System Operating Limits

1. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

2. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

VAR-002-WECC-1 — Automatic Voltage Regulators

1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

   More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

VAR-501-WECC-1 — Power System Stabilizer

1. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a

justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

Conclusion

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC's Response to NERC's Comments
August 13, 2008
Draft

INTRODUCTION

WECC appreciates NERC staff's evaluation of the proposed WECC Regional Reliability Standards (RRSs) in accordance with NERC's Regional Reliability Standards Evaluation Procedure. These proposed WECC RRSs were developed as permanent replacements for the eight WECC Tier 1 RRSs that previously were approved by NERC and FERC. WECC asserts that the seven proposed standards contain all the performance elements of a Reliability Standard that are contained in the NERC Reliability Standards Development Procedure. In addition, the seven proposed standards address and implement the refinements directed by FERC's order on June 8, 2007 (see FERC Docket No.
RR07-11-000) and requested by NERC in its letter dated January 9, 2007. Finally, these proposed standards implement refinements to the approved WECC Tier 1 RRSs which were recommended during the previous expedited direct translation standard development processes.

The attached WECC responses individually address each NERC comment. However, many of the comments submitted by NERC staff relate to refinements that NERC has made to the format of its Reliability Standard Template. These refinements have not been formally approved by NERC, nor have they been transmitted to the regions for comment or additional information, and were therefore unavailable to WECC during the development process. Consequently, WECC has determined not to reopen the standards development process at this stage to address these non-substantive formatting concerns. In addition, during the standards development process, WECC staff twice requested that NERC staff review the proposed WECC standards. WECC did this to ensure that the WECC standard drafting teams were complying with NERC's Regional Reliability Standards Evaluation Procedure as well as its Reliability Standards Development Procedure. NERC did not perform the evaluation of these proposed standards until WECC had completed its Process for Developing and Approving WECC Standards. WECC intends to implement the requested formatting refinements and any potential FERC-directed changes during the next revision of these standards or the next FERC compliance filing.

The proposed WECC RRSs were considered and adopted pursuant to the Process for Developing and Approving WECC Standards. Unless they are approved in their current form, WECC will have to reinitiate the entire process. The consequences of rejecting these WECC RRSs in their entirety would be counterproductive to reliability in the Western Interconnection.

The proposed WECC RRSs will enhance reliability in the Western Interconnection and they will significantly improve the existing eight WECC RRSs because they:

1. Implement ordered NERC and FERC refinements to the existing standards ordered;
2. Eliminate conflicting NERC and WECC requirements contained in the existing RRSs;
3. Include all the Performance Elements of a Reliability Standard;
4. Clarify existing WECC RRSs;
5. Align better with NERC's Functional Model, and
6. Address industry stakeholder concerns.

Therefore, WECC requests the NERC staff recommend approval of these standards to the NERC Board and FERC.

WECC's responses to NERC's initial evaluation are provided in Attachment 1.

Attachment 1

NERC's Written Comments
July 30, 2008
WECC's Written Responses
August 13, 2008

Summary of Findings

<u>BAL-002-WECC-1 — CONTINGENCY RESERVES</u>

NERC COMMENT:
In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

5. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

WECC RESPONSE:

1. The requirements in the BAL-002-WECC-1 Standard as written are clear. Industry stakeholders did not submit any comments questioning the clarity of the standard, nor did they identify a need for an equation. The drafting team does not believe there is any ambiguity in the requirements.

NERC COMMENT:

6. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

    R3. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

    R3.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

    R3.2. Capable of fully responding within ten minutes.

WECC RESPONSE:

2. The drafting team wrote the BAL-002-WECC-1 Standard to permit load, Demand-Side Management (DSM), generation, or another resource technology that qualifies as Spinning Reserve or Contingency Reserve to be used as such. In the case of DSM, the declared amount would be required to respond automatically to frequency deviations and be capable of fully responding in 10

minutes. Loads and DSM are not allowed as Spinning Reserve because it is not permitted by the NERC Spinning Reserve definition. NERC requires that the BAL-002-WECC-1 Standard drafting team use NERC's Spinning Reserve definition. If NERC were to modify its Spinning Reserve definition to allow frequency responsive load tripping as part of a Balancing Authority's DSM, then its use would be permitted under the requirements of the BAL-002-WECC-1 Standard as proposed.

NERC COMMENT (continued):

In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

WECC RESPONSE (continued):

DSM that is deployable within 10 minutes is a subset of Interruptible Load. Interruptible load is defined in requirement R3.2 as an acceptable type of Contingency Reserve. As described previously, if NERC modifies its Spinning Reserve and Interruptible Load definitions, then it would be clear that qualifying DSM is permitted as part of Spinning and Contingency Reserves.

NERC COMMENT:

7. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

WECC RESPONSE:

3. The drafting team wrote a paper titled "WECC Standard BAL-002-WECC-1 Contingency Reserves" that provides an explanation supporting the modification. The paper was included as part of the standards approval package filed on June 11, 2008 with NERC.

NERC COMMENT:

8. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

WECC RESPONSE:

4. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>FAC-501-WECC-1 — TRANSMISSION MAINTENANCE</u>

NERC COMMENT:
It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

3. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

WECC RESPONSE:
1. "Transmission Facilities" is not a NERC-defined term in the NERC "Glossary of Terms Used in Reliability Standards" document, although "Transmission" and "Facility" are. The standard drafting team did not capitalize "transmission facilities" because it believes that the combination of these two defined terms was too limiting. WECC recognizes that this may create confusion and it proposes to address this issue during the next revision of these standards or the next FERC compliance filing.

NERC COMMENT:
4. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:
2. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

IRO-006-WECC-1 — QUALIFIED TRANSFER PATH UNSCHEDULED FLOW (USF) RELIEF

NERC COMMENT:

4. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

WECC RESPONSE:
1. The proposed IRO-006-WECC-1 Standard contains all the key reliability requirements and technical elements from the Unscheduled Flow Mitigation Plan (UFMP) that were included in IRO-STD-006-0. The proposed IRO-006-WECC-1 Standard uses NERC's Functional Model terminology to mitigate unscheduled flow <u>during the next operating hour</u>. It is not necessary to reference the remainder of the UFMP because the remaining items contain procedural requirements explaining "how," not "what." The proposed IRO-006-WECC-1 Standard includes requirements to reduce schedules, which then require adjustments to generation patterns. This prevents potential overloads <u>during the next operating hour</u>. Importantly, the requirements for mitigation of an actual (real-time) overload are contained in TOP-007-WECC-1.

NERC COMMENT:

5. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

WECC RESPONSE:

2. WECC acknowledges the difference between the NERC and WECC definitions for Transfer Distribution Factor (TDF). This is caused by the differences between the Eastern Interconnection Transmission Loading Relief process and the Western Interconnection UFMP. This difference in definitions exists even today between the existing FERC-approved IRO-STD-006-0 Standard and the NERC Glossary. Rejecting the proposed standard will not resolve this difference. WECC will work with NERC to resolve this and intends to make any necessary refinements during the next revision of this standard or the next FERC compliance filing. Despite the difference in the TDF definitions, **the proposed standard corrects a basic difference between the existing FERC-approved IRO-STD-006-0 Standard, which places reliability responsibilities upon the Load Serving Entities (LSEs), and the NERC Functional Model.** LSEs do not have the ability to ensure the implementation of the schedule adjustments required in the existing FERC-approved IRO-STD-006-0 Standard.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

5. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

PRC-004-WECC-1 — PROTECTION SYSTEM AND REMEDIAL ACTION SCHEME MISOPERATION

NERC COMMENT:

5. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

WECC RESPONSE:

1. WECC recognizes that the standard drafting team included explanatory text in the requirement section in an attempt to clarify the requirements. However, the duplication does not adversely

impact the applicability, clarity, or the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

6. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

WECC RESPONSE:

2. WECC recognizes that the standard drafting team included System Operators and System Protection personnel in the requirements. R1. of PRC-004-WECC-1 states that, **"System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection Systems and RAS operations."** As written the requirement is sufficiently clear and well-defined to be enforceable on the entities in the Western Interconnection. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

7. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

WECC RESPONSE:

3. WECC recognizes that the standard drafting team included explanatory text in the requirement section that might be more appropriately included as a footnote. However, the text clarifies the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

8. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

WECC RESPONSE:

4. The requirements in the PRC-004-WECC-1 Standard are clearly written. Industry stakeholders did not submit any comments questioning the clarity of the standard. The alternative standard drafting formats or language used in this standard, are applicable exclusively to the Western Interconnection. These stylistic differences do not affect others and should not be a consideration for NERC approval.

<u>TOP-007-WECC-1 — SYSTEM OPERATING LIMITS (SOLs)</u>

NERC COMMENT:

3. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable

operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

WECC RESPONSE:

1. In the Western Interconnection, SOLs are designed so that during steady-state operations, with all lines in service, the system is at least two contingencies away from cascading. Therefore, exceeding an SOL for the 40 major paths identified in the TOP-007-WECC-1 Standard would not typically qualify as an Interconnection Reliability Operating Limit (IROL) under NERC's TOP-007-0 Standard. The standard drafting team created the TOP-007-WECC-1 Standard to limit the amount of time that a SOL may be exceeded for these very important paths, which makes the TOP-007-WECC-1 Standard more stringent than the NERC standard.

NERC COMMENT:

4. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

WECC RESPONSE:

2. The existing standard created confusion during system operation because system conditions may change the limiting conditions on a path. This is because the limit depends upon whether thermal, stability, or post transient limitations are the limiting factor. In addition, having different response times for paths (and sometimes for the same path depending on current outage conditions), complicates system operation, causing delays in responding to the path overload. This resulted in path operators implementing more drastic actions to respond to a contingency within 20 minutes, which may put the system at greater risk, particularly during heavy load periods such as summer. The standard drafting team determined that changing the standard from a 20-minute to a 30-minute response time is insignificant in terms of the probability of a next contingency occurring. Moreover, the drafting team believes that following a system disturbance, the system operators will be better able to identify what generation to ramp in order to be effective in mitigating the overload. This will also allow them to coordinate with others before implementing the generation ramps. Therefore, the simplification of the standard to one consistent 30-minute period improves reliability. It is important to recognize that in spite of extending the recovery period, the refinement should improve system reliability.

<u>VAR-002-WECC-1 — AUTOMATIC VOLTAGE REGULATORS (AVRs)</u>

NERC COMMENT:

4. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-002-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002a-1 Standard. The 98 percent in Requirement R1. of VAR-002-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002a-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring the AVR to be in service provides for time to start up generating facilities. It also allows for evaluation when the Generator Operators respond to unforeseen events.

NERC COMMENT (continued):
More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

WECC RESPONSE (continued):
NERC VAR-002-1a R1. permits the Generator Operator to operate in different modes by simply notifying the Transmission Operator. There are no restrictions on the length of time or reasons for operating in other modes. The WECC 1996 outage reports identified the lack of reactive support from generators with AVRs operating in modes other than voltage control as one of the causes of the WECC 1996 outages. The VAR-002-WECC-1 Standard limits the reasons and time for operating a generator without the AVR in service and controlling voltage, therefore it is more stringent than the NERC VAR-002-1a Standard.

NERC COMMENT
5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:
2. There is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the AVR in service). The use of peaking units adds to overall system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture recommendations.

NERC COMMENT:
6. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:
3. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>VAR-501-WECC-1 — POWER SYSTEM STABILIZER (PSS)</u>

NERC COMMENT:

4. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-501-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002b-1 Standard. The 98 percent in Requirement R1. of VAR-501-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002b-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring PSS to be in service provides time for evaluation and to start up generating facilities when Generator Operators respond to unforeseen events.

NERC COMMENT:

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the exiting standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the PSS in-service). Operating at low megawatt levels makes the PSS ineffective. The use of peaking units adds to over-all system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture PSS in service recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes that the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

(NERC) CONCLUSION

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC RESPONSE
WECC appreciates the opportunity to discuss NERC staff's initial evaluation and report in conference calls on August 4 and 5, 2008 and to provide the written clarifications and responses contained herein. We trust that WECC's responses, along with all the supporting documentation contained in WECC's submissions, provide the NERC staff a comprehensive basis for recommending NERC Board of Trustees approval of all proposed standards. Please direct any questions relating to WECC's response to WECC Director of Standards, Steve Rueckert at steve@wecc.biz or (801) 883-6878.

Appendix 6

WECC Responses to FERC Staff Concerns and Questions Regarding the Proposed WECC Tier 1 Standards
June 17, 2008

I. Contingency Reserves – BAL-002-WECC-1

A. Period of Contingency Reserve Restoration: Does the proposed standard modify the current standard to provide a longer period of time of 90 minutes rather than 60 minutes?

Yes, the requirement to restore contingency reserves within 60 minutes was eliminated in the proposed standard. The current standard requires the restoration of contingency reserves within the first 60 minutes following an event. By eliminating this requirement in the proposed standard, WECC adopts the NERC default standard that requires the restoration of contingency reserves within 90 minutes from the end of the disturbance recovery period.[2]

The 60 minute restoration period required by the current standard was developed and used under a manual interchange transaction structure among vertically integrated utilities. As the electric utility industry restructured, there has been a substantial increase in the number of market participants and interchange transactions.[3] To accommodate the increase in number of interchange transactions and market participants an electronic tagging system was implemented in the Western Interconnection. The adoption of an electronic tagging system that accommodates multiple market participants and a large number of interchange transactions made the current mid-hour reserve restoration more cumbersome and made the inappropriate rejection of reserve restoration transactions more likely because such transactions are outside the electronic tagging cycle.

Eliminating the 60 minute reserve restoration requirement and adopting the NERC requirements results in more efficient communication among Balancing Authorities (BAs) because it aligns the restoration of contingency reserves with the electronic tagging system approval cycle. Adopting the NERC contingency reserve restoration requirements reduces the potential for reserve transactions being inappropriately rejected resulting in improved communication among BAs resulting in improved reliability.

B. Shedding of Firm Load: Does the proposed standard change the treatment of the shedding of firm load compared to the current standard?

No, both standards allow for the shedding of firm load under limited circumstances. The addition of requirement R3.4 in the proposed standard clarified the process. During capacity and energy emergencies, a BA or Reserve Sharing Group (RSG) may use load as non-spinning reserves; that is BAs and RSGs will not drop load to maintain their non-spinning reserve requirement. Rather they will use load as part of their non-spinning contingency reserves.

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[2] See NERC Standard BAL-002-0 Requirement R6 and WECC Standard BAL-STD-002-0 WR1.d.

[3] Balancing Authorities in the Western Interconnection approve between 2,500 and 4,500 interchange transactions per day.

This standard emphasizes the responsibility of serving customer load first while at the same time protecting the reliability of the Western Interconnection. Even during capacity and energy emergencies, BAs and RSGs are required to comply with the spinning reserve requirements.

C. Deliverability of Contingency Reserves: Does the proposed standard require that contingency reserves be deliverable?

   Yes, nothing has changed with respect to the deliverability of contingency reserves.

D. Interruptible Imports: In the current standard the sink BA is required to carry an additional amount of contingency reserves equal to the amount of interruptible imports. Does the proposed standard have the same requirement?

   Yes, the term interruptible imports was eliminated from the proposed standard. It was replaced with the added requirement R1.2 which requires that "If the Source BA designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink BA shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s)." This is an improvement from the current standard because it eliminates ambiguity in the term interruptible imports.

E. Demand Side Management: Did the drafting team comply with FERC Order 693 to explicitly allow demand-side management (DSM) to be used for reserves?

   Yes, DSM that is deployable within 10 minutes is a subset of interruptible load. Interruptible load is defined in requirement R3.2 as an acceptable type of contingency reserve.

II. Qualified Transfer Path Unscheduled Flow Relief- IRO-006-WECC-1

A. Is the proposed standard intended to address an actual (real time) overload situation?

   No, a different standard TOP-007-WECC-1 covers actual (real time) overload situations. The proposed IRO-006-WECC-1 standard includes requirements to reduce schedules, which requires adjustments to generation patterns, to prevent potential overloads during the next operating hour.

B. Should the Unscheduled Flow Mitigation Plan (UFMP) be incorporated in the IRO-006-WECC-1 by reference?

   No, the key reliability portions from the UFMP are incorporated in the proposed standard. It is not necessary to reference the remainder of the UFMP.

C. Does the WECC UFMP need to be updated?

   Yes, WECC has initiated the process of updating its UFMP.

III. System Operating Limits—TOP-007-WECC-1

A. Could the language in TOP-007-WECC-1 allow for the system to be less than two contingencies away from cascading and more specifically one contingency away from cascading?

No, the proposed standard is designed such that path operations must be at least two contingencies away from cascading during steady state operations. In real time operations when System Operating Limits (SOL) are exceeded for periods not to exceed 30 minutes, there may be system conditions that are less than two contingencies away from cascading.

B. Could IRO-005-2 Requirements R3 and R5 be interpreted that the power system is being operated two contingencies away from a cascading outage while WECC TOP-007-WECC-1 requirement R1 results in the power system being operated one contingency away from a cascading outage?

No, IRO-005-2 requirements R3 and R5 are consistent with the requirements in TOP-007-WECC-1. In the Western Interconnection SOLs are developed in such a manner that the system operation is at least two contingencies away from a cascading failure. This is implicit in the identification of the SOL derivation. If, however, there is a flow that exceeds the SOL, Transmission Operators (TOP) and Reliability Coordinators (RC) must take proactive immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the transmission path exceed the SOL for more than 30 minutes, thus protecting the system from potential cascading for a subsequent contingency.

C. Do SOL changes within the hour extend the time for compliance?

No, SOL changes within an operating hour do not extend the time for compliance.

IV. Automatic Voltage Regulators and Power System Stabilizers – VAR-002-WECC-1 and VAR-501-WECC-1

A. How does VAR-002-WECC-1 coordinate with the new NERC Standard VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules?

VAR-002-WECC-1 contains specific, more restrictive, requirements on generator operators regarding the operation of Automatic Voltage Regulators (AVR) that are not contained in the NERC Standard VAR-002-1. The reasons for these more restrictive requirements are to support transfer capabilities in the Western Interconnection and to address the insufficient supply of reactive power identified as a cause of the 1996 system disturbances in the Western Interconnection. The drafting team designed the VAR-002-WECC-1 Standard to limit the reasons for operating AVRs in a mode that does not control voltage and the amount of time permitted for such operations. Generator operators are still required to comply with all the requirements contained in NERC VAR-002-1.

B. Are Power System Stabilizers (PSS) included in either of these standards?

Yes, VAR-501-WECC-1 contains requirements regarding the in-service operation of PSS.

C. Why were the AVR and PSS replacement period extended to two years from 15 months?

The amount of time to replace AVR and PSS was lengthened to accommodate the approval and procurement time frames for AVR and PSS for nuclear power plants, which are two years.

V. Transmission Maintenance – FAC-501-WECC-1

A. Does the FAC-501-WECC-1 standard reduce the number of lines that are subject to this standard to the SOL limiting factors from the lines and facilities associated with the 40 paths thereby reducing the obligation for maintenance?

No, there is no change in the number of lines or facilities subject to the proposed FAC-501-WECC-1 standard.

CONSIDERATION OF COMMENTS FOR VAR-002-WECC-1 — AUTOMATIC VOLTAGE REGULATOR
COMMENTS WERE DUE JANUARY 2, 2008
JANUARY 24, 2008

The VAR-002-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the WECC VAR-002-WECC-1 Standard. This Standard was posted for a 30-day public comment period from November 30, 2007 through January 2, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard by posting comments on the WECC website. There were six sets of comments from five companies.

In this 'Consideration of Comments' document, stakeholder comments have been organized so that it is easier to see the responses associated with each comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Steve Rueckert at 801-582-0353 or at steve@wecc.biz. In addition, there is a WECC Appeals Process.

Comments and Responses

Your response to my original comment states the following:

Reply: The NERC standard VAR-001-1 Requirement 4 requires Transmission Operators to provide voltage schedules. Implementing this recommendation would duplicate an existing NERC requirement. Therefore, the drafting team did not implement the recommendation

Your response is factually incorrect...the NERC standard does not require the TO to provide a voltage schedule...it gives the TO the option of providing either a voltage schedule or a reactive power schedule. The exact language from R4 is quoted below:

"Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator"

The WECC standard is inconsistent with permitting the TO to use a reactive power schedule instead of a voltage schedule. That is why my original comment is still valid and still needs to be addressed in the standard.

John Stout

Reply: The drafting team does not believe there is any inconsistency between VAR-002-WECC-1 and NERC VAR-001-1. The second sentence in NERC VAR-001 Requirement 4 states:

> "The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage)."

The parenthetical indicates that the AVR is always to be controlling voltage whether the Transmission Operator provides a voltage or VAR schedule.

Many Qualified Facilities (QF) in California were connected to the BES under the California Public Utility Commission (CPUC) Rule 21. Some Utilities in their interpretation of Rule 21 required the QF to operate the AVR in Power Factor (pf) mode as a condition of the Interconnection Agreement (ICA) and Power Purchase Agreement (PPA). Requiring the QF to now operate in the AVR in automatic, controlling voltage, puts operation of these plants in conflict with the criteria used for the Reliability, Safety, and Stability Studies of the BES that were completed by the Transmission Operator (TOP) at the time of the interconnection. Operating in the voltage control mode also puts the QF in conflict with the contractual conditions with the TOP currently in force.

The above is in conformance with NERC Standard VAR-002 and the current NERC interpretation of that standard as referenced in WECC-VAR-STD-002a. The relief given in the draft VAR-002-WECC-1 R1.10 only temporarily deals with the specific instability due to a LTC in the area and does not address the above issues.

The PPAs for QFs requires them to pay for VARs taken and not be paid for VARs given to the grid. Operating in the voltage control mode with the set point, as directed by the TOP, does not allow the QF any control over the movement of VARs to and from the BES and can be a severe financial hardship.

Roger Robinson
rmc@att.net

Reply: CPUC Rule 21 only applies to generators on distribution systems. This standard applies to synchronous generators and condensers that are connected to the Bulk Electric System.

Considerations for VAR-002-WECC-1

Comment on Purpose Statement:

The purpose statement's intent is not as clear as the previous version of the standard. Is the purpose to just have AVR equipment, or is it to have AVR equipment and operate the equipment in a certain manner.

Reply: The drafting team made refinements to the purpose statement to clarify the statement.

Is the purpose to have Automatic Voltage Regulator equipment installed on, fully functional, and in service whenever a qualifying synchronous generator or condenser is connected to the interconnected transmission system?

Reply: The VAR-002-WECC-1 standard applies to the same entities to which the NERC Reliability Standards apply.

Clarification of 4.3.

This paragraph seems to be very inclusive in its scope. There may be circumstances where a synchronous generator is connected to the BES, but it does not qualify under NERC criteria (the unit is smaller than 20 MVA, the aggregate plant is smaller than 75 MVA, etc.).

Reply: The NERC Functional Model registration criterion governs which units are subject to compliance regarding VAR-002-WECC-1. This is true for all NERC Reliability Standards.

Further, there are circumstances where a generating unit or plant may not be a contributing element to system reliability, regardless of its AVR. There should be provisions, similar to provisions in the NERC standard, for a Transmission Operator to exempt some units or plants based on thorough analysis that demonstrates there is no adverse impact. It may be prudent to subject those studies to some type of review and concurrence if the exemption is being provided for plants that are larger in aggregate size.

Reply: These standards are developed under the assumption that all generating units contribute to system reliability. It is not practicable to determine the unit's contribution because its contribution can vary depending upon the continuously changing conditions of the system. The drafting team does not believe that the Transmission Operator's discretion provides a carte blanche exemption to the standard. This standard qualifies what type of operation may be excluded.

General Suggestion to add to section 4:

If this is intended to work in companion with the NERC standard, would it be appropriate to include a reference that this is intended to work in companion with NERC VAR-002. The NERC VAR-002 has a number of reporting requirements regarding this operation, which are not part of this standard, and while entities should be aware of the order of precedent, a statement here would help with overall compliance efforts.

Reply: This standard will become part of the body of the NERC Reliability Standards. References to other NERC standards are not necessary.

Comment on R1.

This appears to be a significant change from previous standards. Previous standards required operation of the AVR in a voltage control mode. This version does not appear to specifically require operation in the voltage control mode. I would interpret this that if I had an AVR operating in power factor mode or VAR control mode, it would be compliant. The previous standard was more specific in identifying the voltage control mode. The intent of what is the intended control mode should be stated.

Reply: The drafting team refined R1 to require operation in automatic voltage control mode.

A similar comment to one already stated above, the Transmission Operator should be given authority to provide exemptions from this operating mode through either analysis or specific operating direction. While the NERC standard provides for this, it is not clear that this standard does. This is an area where the two standards appear to be in conflict. If a generator is directed by the Transmission Operator to operate in a different mode, does this violate this proposed standard?

Reply: There are no normal operating configurations that would require a Transmission Operator to request operation in a mode other than automatic voltage control mode. If the Transmission

Operator requires a generator to operate in an operating mode other than voltage control mode, then those hours would be counted as operating without AVR in service. The generator can still meet a VAR schedule request with the AVR in automatic voltage control mode.

Comment on R1.1

The drafting team should consider establishing a specific threshold of hours given that there are small differences in hours between quarters. For example, the equipment operates less than (3 mon/qtr X 30 days/mon X 24 hrs/day X 5% =) 108 hours per calendar quarter.

It would be desirable to increase the threshold to something more like 200 hours. This number of hours is derived from a reasonable number of hours that a simple cycle emergency peaking CT might run if it was fitted with reasonably available control technology (RACT) for controlling emission levels. This would help Generator Owners with complying with the need of this standard, but not reach into units, which seldom run, and are limited in their run time by emission permit conditions and emergency peaking operations.

Reply: The standard drafting team believes a percentage is more appropriate. The intent of the standard is to keep the AVR in service and not designed to avoid having to purchase an AVR. Lengthening the exemption in R1.1 to 200 hours would amount to doubling the 5% exclusion. The drafting team does not believe this is justifiable.

Comment on R1.5 and R1.6

It would seem to simplify the standard if these were combined and the 15 month provision retained. In both exceptions, documentation must be submitted to explain the need to have the AVR out of service. It is not clear why from system reliability and performance standard perspective, there is a need to distinguishing between replacement parts or system replacement.

Reply: The drafting team extended the time for AVR replacement to 24 months to accommodate design and procurement especially for nuclear units. There is a distinction between the time required to repair an AVR versus replacement.

Comment on R1.10

This seems unduly restrictive. The ability for the Transmission Operator to direct the Generator Operator to operate the excitation system in other modes should not be restricted by a singular occurrence of a LTC operation. The LTC should be removed. The provisions for the Transmission Operator to direct the Generator Operator to operating in modes other than automatic modes could be incorporated with R1.8.

Reply: In R1 the drafting team has provided exclusions for credible situations for the Transmission Operator to direct operating without the AVR in automatic voltage control. R1.8 permits the Transmission Operator to allow a unit to operate when the AVR is **unavailable for service** without a violation.

Comment on R2

Clearly, there is a need for the Generator Operator and Transmission Operator to have timely (i.e. quarterly) documentation of the out of service hours and to document the reason for the out of service hours. Consideration should be given to determine how much detail information needs to be reported. For example, is it critical to report that each exclusion be separately reported? These records are required to be kept by the asset owner to support the reported data and the Compliance Enforcement Authority has abilities to require these records be produced if there are concerns about the quality of the reporting of a particular entity. How would this data be used by the Reliability Coordinator if it was reported? It would seem the most critical element is how many hours the AVR was in service while the generator/condenser is operating. Could the report be simply limited to a hour many hours the unit ran against the hours the AVR is in service?

Reply: The Compliance Enforcement Authority will develop reporting instructions including reporting forms, the date data are due, and other data retention requirements for audits. It is the responsibility of the Transmission Operator to know the status of all reactive resources. Compliance reporting is never submitted to the Reliability Coordinator.

Anonymous

Comment on Purpose Statement:

The purpose statement's intent is not as clear as the previous version of the standard. Is the purpose to just have AVR equipment, or is it to have AVR equipment and operate the equipment in a certain manner.

Reply: The drafting team made refinements to the purpose statement to clarify the statement.

Is the purpose to have Automatic Voltage Regulator equipment installed on, fully functional, and in service whenever a qualifying synchronous generator or condenser is connected to the interconnected transmission system?

Reply: The VAR-002-WECC-1 standard applies to the same entities to which the NERC Reliability Standards apply.

Clarification of 4.3.

This paragraph seems to be very inclusive in its scope. There may be circumstances where a synchronous generator is connected to the BES, but it does not qualify under NERC criteria (the unit is smaller than 20 MVA, the aggregate plant is smaller than 75 MVA, etc.).

Reply: The NERC Functional Model registration criterion governs which units are subject to compliance regarding VAR-002-WECC-1. This is true for all NERC Reliability Standards.

Further, there are circumstances where a generating unit or plant may not be a contributing element to system reliability, regardless of its AVR. There should be provisions, similar to provisions in the NERC standard, for a Transmission Operator to exempt some units or plants based on thorough analysis that demonstrates there is no adverse impact. It may be prudent to subject those studies to some type of review and concurrence if the exemption is being provided for plants that are larger in aggregate size.

Reply: These standards are developed under the assumption that all generating units contribute to system reliability. It is not practicable to determine the unit's contribution because its contribution can vary depending upon the continuously changing conditions of the system. The drafting team does not believe that the Transmission Operator's discretion provides a carte blanche exemption to the standard. This standard qualifies what type of operation may be excluded.

General Suggestion to add to section 4:

If this is intended to work in companion with the NERC standard, would it be appropriate to include a reference that this is intended to work in companion with NERC VAR-002. The NERC VAR-002 has a number of reporting requirements regarding this operation, which are not part of this standard, and while entities should be aware of the order of precedent, a statement here would help with overall compliance efforts.

Reply: This standard will become part of the body of the NERC Reliability Standards. References to other NERC standards are not necessary.

Comment on R1.

This appears to be a significant change from previous standards. Previous standards required operation of the AVR in a voltage control mode. This version does not appear to specifically require operation in the voltage control mode. I would interpret this that if I had an AVR operating in power factor mode or VAR control mode, it would be compliant. The previous standard was more specific in identifying the voltage control mode. The intent of what is the intended control mode should be stated.

Reply: The drafting team refined R1 to require operation in automatic voltage control mode.

A similar comment to one already stated above, the Transmission Operator should be given authority to provide exemptions from this operating mode through either analysis or specific operating direction. While the NERC standard provides for this, it is not clear that this standard does. This is an area where the two standards appear to be in conflict. If a generator is directed by the Transmission Operator to operate in a different mode, does this violate this proposed standard?

Reply: There are no normal operating configurations that would require a Transmission Operator to request operation in a mode other than automatic voltage control mode. If the Transmission Operator requires a generator to operate in an operating mode other than voltage control mode, then those hours would be counted as operating without AVR in service. The generator can still meet a VAR schedule request with the AVR in automatic voltage control mode.

Comment on R1.1

The drafting team should consider establishing a specific threshold of hours given that there are small differences in hours between quarters. For example, the equipment operates less than (3 mon/qtr X 30 days/mon X 24 hrs/day X 5% =) 108 hours per calendar quarter.

It would be desirable to increase the threshold to something more like 200 hours. This number of hours is derived from a reasonable number of hours that a simple cycle emergency peaking CT might run if it was fitted with reasonably available control technology (RACT) for controlling emission levels. This would help Generator Owners with complying with the need of this standard, but not reach into units, which seldom run, and are limited in their run time by emission permit conditions and emergency peaking operations.

Reply: The standard drafting team believes a percentage is more appropriate. The intent of the standard is to keep the AVR in service and not designed to avoid having to purchase an AVR. Lengthening the exemption in R1.1 to 200 hours would amount to doubling the 5% exclusion. The drafting team does not believe this is justifiable.

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It would seem to simplify the standard if these were combined and the 15 month provision retained. In both exceptions, documentation must be submitted to explain the need to have the AVR out of service. It is not clear why from system reliability and performance standard perspective, there is a need to distinguishing between replacement parts or system replacement.

Reply: The drafting team extended the time for AVR replacement to 24 months to accommodate design and procurement especially for nuclear units. There is a distinction between the time required to repair an AVR versus replacement.

Comment on R1.10

This seems unduly restrictive. The ability for the Transmission Operator to direct the Generator Operator to operate the excitation system in other modes should not be restricted by a singular occurrence of a LTC operation. The LTC should be removed. The provisions for the Transmission Operator to direct the Generator Operator to operating in modes other than automatic modes could be incorporated with R1.8.

Reply: In R1 the drafting team has provided exclusions for credible situations for the Transmission Operator to direct operating without the AVR in automatic voltage control. R1.8 permits the Transmission Operator to allow a unit to operate when the AVR is **unavailable for service** without a violation.

Comment on R2

Clearly, there is a need for the Generator Operator and Transmission Operator to have timely (i.e. quarterly) documentation of the out of service hours and to document the reason for the out of service hours. Consideration should be given to determine how much detail information needs to be reported. For example, is it critical to report that each exclusion be separately reported? These records are required to be kept by the asset owner to support the reported data and the Compliance Enforcement Authority has abilities to require these records be produced if there are concerns about the quality of the reporting of a particular entity. How would this data be used by the Reliability Coordinator if it was reported? It would seem the most critical element is how many hours the AVR was in service while the generator/condenser is operating. Could the report be simply limited to a hour many hours the unit ran against the hours the AVR is in service?

Reply: The Compliance Enforcement Authority will develop reporting instructions including reporting forms, the date data are due, and other data retention requirements for audits. It is the responsibility of the Transmission Operator to know the status of all reactive resources. Compliance reporting is never submitted to the Reliability Coordinator.

Posted by: Crystal Musselman
Avista Corp.

Considerations for VAR-002-WECC-1

Comment on R1.9 and R1.10

It would seem to simplify the standard if these were combined and the 15 month provision retained. In both exceptions, documentation must be submitted to explain the need to have the AVR out of service. It is not clear why from system reliability and performance standard perspective, there is a need to distinguishing between replacement parts or system replacement.

Crystal Musselman

Reply: The drafting team extended the time for AVR replacement to 24 months to accommodate design and procurement especially for nuclear units. There is a distinction between the time required to repair an AVR versus replacement.

The Alberta Electric System Operator (AESO) appreciates the opportunity to comment and would like to offer the following:

- The AESO currently reports AVR data to the WECC on behalf of all Generator Operators in Alberta, instead of each GOP reporting individually.

- It may be worthwhile to review how and if R1.1 fit in the overall R1 requirement together with the other listed "exceptions." It would seem logical, and R1 does seem to imply that, if a generator was operated for less than 5% of time in a calendar quarter, then the generator (versus the time period when AVR was not in service) is to be excluded from the 98% requirement. However, the wording in R1 doesn't quite say that literally. Please review and revise as required.

Thank you.

Anita Lee, P. Eng.
Manager, Operating Policies and Procedures
Alberta Electric System Operator

Reply: The drafting team made refinements to R1 to clarify the requirement. If the unit does not operate five percent or more of all hours during a quarter, the hours the unit operated without AVR may be excluded from the in service percentage calculation.

Drafting Team for VAR-002-WECC-1 and VAR-501-WECC-1

FIRST NAME	LAST NAME	COMPANY
Baj	Agrawal	Arizona Public Service Company
John	Amos	Siemens Power Generation, Inc.
Greg	Anderson	Southern California Edison
Phillip	Anderson	Idaho Power Company
Waylon	Bowers	US Army Corps of Engineers
Karl	Bryan	US Army Corps of Engineers
Guy	Colpron	Idaho Power Company
Thomas	Foster	Reliant Energy - Ormond Beach Generation Station
George	Girgis	US Department of the Interior
Daniel	Hansen	Reliant Energy
Jerry	Smith	Arizona Public Service Corporation
Ken	Wilson	Western Electricity Coordinating Council
Shane	Kronebusch	British Columbia Hydro
Greg	Lange	Public Utility District No. 2 of Grant County
James	Murphy	Bonneville Power Administration
F.	Okapal	PacifiCorp East
Richard	Padilla	Pacific Gas and Electric Company
Paul	Rice	Western Electricity Coordinating Council
Gerry	Sauve	US Army Corp

OPERATING COMMITTEE

VAR-002-WECC-1

SP - State and Provincial
TP - Transmission Provider
TC - Transmission Customer
IS - Interested Stakeholder

Appendix 9

Name of Organization	Name of Voting Member	Voting Class	YES	NO	Abstain
Alberta Electric System Operator (AESO)	Doug Hincks	TP	X		
AltaLink L.P. (ALTA)	Rick Spyker	TP	X		
Aquila Networks-WPC (WPE)	Al Logan	TC			X
Arizona Public Service (AZPS)	Mark Hackney (alternate)	TP	X		
Arizona Public Service (AZPS)	David Hansen	TC	X		
ATCO Electric Ltd. (ATCO)	Blaine Beisiegel	TP	X		
Avista Corp	Scott J. Kinney (alternate)	TP		X	
Basin Electric Power Cooperative (BEPC)	Becky Kern	TC			X
Bear Energy LP (BEAR)	Jeff Winkler (alternate)	TC	X		
Black Hills Power and Light Company (BHPL)	Pam Pahls	TP	X		
Bonneville Power Administration-Power Bus Line (BPAP)	Fran Halpin	TC	X		
Bonneville Power Administration-TBL (BPAT)	Don Watkins	TP	X		
BP Energy Company	Julie Martin	TC		X	
British Columbia Hydro and Power Authority (BCHA)	Clement Ma	TC	X		
British Columbia Transmission Corporation (BCTC)	Devinder Ghangass	TP	X		
California Department of Water Resources (CDWR)	Glenn Solbert	TC	X		
California Energy Commission (CEC)	Bill Chamberlain (alternate)	SP	X		
California ISO (CISO)	James McIntosh	TP	X		
California Mexico Reliability Center	Greg Tillitson - TC	IS	X		
Calpine Corporation (CALP)	Frank Obertance	TC	X		
Colorado Springs Utilities (CSU)	Steve Schaarschmidt	TP	X		
Deseret Generation & Transmission Co-op (DGT)	Phil Tice	TC	X		
Deseret Generation & Transmission Co-op (DGT)	L'Dee Curtis	TP	X		
Dynegy, Inc. (DYN)	Brian Theaker	TC		X	
El Paso Electric Company (EPE)	Jose Nevarez	TP			X
Eugene Water & Electric Board (EWEB)	Dean Ahlsten	TC	X		
Fortis Energy Marketing & Trading Group (FEMT)	Jay Alexander	TC			X
FPL Energy LLC (FPLE)	Mark J. Smith	TC		X	
Gila River Power, L.P. (PGR)	Kenneth Parker	TC			X
Great Basin Transmission, LLC (GBT)	Ali Amirali	TC		X	
Highland Energy LLC	Bryan Bradshow	IS			X
Idaho Power Company (IPC)	Tessia Park	TP	X		
J. ARON & CO	Cutis Kebler	IS	X		
Metropolitan Water District of Southern California (MWD)	Garry Chinn	TP			X
Mirant Americas, Inc. (MIR)	John Stout	TC		X	
Modesto Irrigation District (MID)	Toxie Burriss	TP		X	
Morgan Stanley Capital Group Inc.	Patrick Murray (alternate)	TC		X	
Northern California Power Agency (NCPA)	Fred Young	TC	X		
NorthWestern Energy (NWMT)	Mark Donaldson (alternate)	TP	X		
NRG Power Marketing, Inc. (NRG)	Robert Bailey	TC		X	
Pacific Gas & Electric (PG&E)	Kris Bucholz	TP	X		
Pacific Gas & Electric (PG&E)	Joe Minkstein	TC	X		
PacifiCorp (PACM)	John Apperson	TC	X		
PacifiCorp (PAC)	Robert Williams	TP	X		
Platte River Power Authority (PRPA)	John R. Powell	TP	X		
Portland General Electric (PGE)	Mike Ryan	TP	X		
Portland General Electric (PGE)	John Jamieson (alternate)	TC			X
Powerex (PWX)	Mike Goodenough	TC			X
PPL EnergyPlus, LLC (PPLE)	John Cummings (Alternate)	TC		X	
PPM Energy, Inc. (PPM)	Diana Scholtes (alternate)	TC	X		
Public Service Company of Colorado (PSC)	Robert Johnson	TP	X		
Public Service Company of Colorado (PSC)	Steve Buening	TC	X		
Public Service Company of New Mexico (PNM)	Keith Nix	TP	X		
Public Service Company of New Mexico (PNM)	David Miller	TC	X		
Public Utility District No. 1 of Chelan County (CHPD)	Hugh Owen	TC	X		
Public Utility District No. 1 of Douglas County (DOPD)	Henry E. (Hank) LuBean	TP	X		
Public Utility District No. 2 of Grant County (GCPD)	Greg Lange	TC		X	
Puget Sound Energy, Inc. (PSE)	Gary Nolan (alternate)	TP	X		
Puget Sound Energy, Inc. (PSE)	Joe Hoerner (alternate)	TC			X
Reliant Energy, Inc. (REI)	Thomas J. Bradish	TC			X
Sacramento Municipal Utility District (SMUD)	Vicken Kasarjian	TC		X	
Salt River Project (SRP)	Mike Hummel	TC	X		
San Diego Gas & Electric Company (SDGE)	Scott Peterson	TP	X		
Seattle City Light (SCL)	Pawel Krupa	TC	X		
Sempra Generation (SER)	Leslie Padilla	TC	X		
Sierra Pacific Resources Transmission (SPR)	Rich Salgo	TP	X		
Sierra Pacific Resources Transmission (SPR)	Sheryl Torrey	TC	X		
Southern California Edison Company (SCE)	Thomas J. Botello	TP	X		
Southern California Edison Company (SCE)	John Pespisa	TC	X		
Southwest Transmission Cooperative, Inc. (SWTC)	Shane Sanders	TP	X		
SUEZ Energy Marketing NA, Inc. (SUEZ)	Caitlan Collins	TC		X	
SWRTA Class 2 Group (SC2G)	Dennis Delaney	TC			X
Tacoma Power (TPWR)	Catherine Leone-Woods	TC	X		
Transmission Agency of Northern California (TANC)	John Forman	TP		X	
Tri-State Generation & Transmission Association, Inc (TSGT)	Thomas A. Smith	TP		X	
Tucson Electric Power Company (TEP)	John Tolo	TP	X		
Turlock Irrigation District (TID)	Casey Hashimoto	TP	X		
U.S. Army Corps of Engineers	Karl Bryan	IS	X		
U.S. Bureau of Reclamation (USBR)	Deon Murphy	TC	X		
Utah Municipal Power Agency (UMPA)	Layne Burningham	TP	X		
Utility System Efficiencies, Inc.	LeRoy Patterson	TC			X
Western Area Power Administration (WAPA)	Edwad Hulls	TP	X		
Western Area Power Administration (WAPA)	Ken Otto	TC	X		

Voting Summary	Class	Yes	No	Abstain
	SP	1	0	0
	TC	25	11	11
	TP	28	4	2
total		54	15	13

Board of Directors			
April 16-18, 2008		Voting Summary	
Coronado, CA		BAL-002-WECC-1	
Last Name	**First Nar**	**Organization**	**Class**
Anderson	Bob	Non-affiliated Director	Non-Affiliated
Areghini	David	Salt River Project	Class 1
Barbash	Carolyn	Sierra Pacific Power Company	Class 1
Beyer	Lee	California Public Utilities Commission	Class 5
Brown	Duncan	Calpine Corporation	Class 3
Campbell	Ric	Utah Public Service Commission	Class 5
Cauchois	Scott	CADRA	Class 4
Chamberlain	Bill	California Energy Commission	Class 5
Cleary	Anne	Mirant Americas, Inc.	Class 3
Conway	Teresa	Powerex Corp.	Class 6
Coughlin	John	Non-affiliated Board Member	Non-Affiliated
Dearing	Bill	Grant County PUD	Class 2
Ferreira	Richard	TANC Executive Advisor	Class 2
Grantham-Richards	Maude	Farmington Electric Utility System	Class 2
Gutting	Scott	Energy Strategies, LLC	Class 4
Kelly	Nancy	Utah Committee of Consumer Services	Class 4
King	Jack	Non-affiliated Board Member	Non-Affiliated
LaFond	Steve	The Boeing Company	Class 4
*Little	Doug	British Columbia Transmission Corporation	Class 6
McMaster	Dale	Alberta Electrical System Operator	Class 6
Moya	Jesus	Comision Federal de Electricidad	Mexico
Newton	Tim	Non-affiliated Director	Non-Affiliated
Sharpless	Jananne	Non Affiliated Board Member	Non-Affiliated
Smith	Marsha	Idaho Public Utilities Commission	Class 5
Stout	John	Mariner Consulting	Class 3
Tarplee	Gary	Southern California Edison	Class 1
Thuston	Tim	Williams Power	Class 3
Weis	Larry	Turlock Irrigation District	Class 2
VanZandt	Vicki	Bonneville Power Administration	Class 1
Zaozirny	Lori Ann	British Columbia Utilities Commission	Class 6
The Board Members listed above voted whether to approve BAL-002-WECC-1.			
Twenty-eight members voted Yes.			
One member (identified with an asterisk) voted No.			
Two members (not identified) abstained.			

VAR-501-WECC-1 — Power System Stabilizer

Action: VAR-501-WECC-1 — Power System Stabilizer — **Approve**

Proposed Effective Date: On the first day of the first quarter, after applicable regulatory approval.

Summary Conclusion and Recommendation:

- NERC recommends approval of VAR-501-WECC-1 — Power System Stabilizer and associated definition, "Commercial Operation" on the basis that the Regional Reliability Standard addresses matters that the continent-wide NERC Reliability Standards do not, thus satisfying the statutory criteria for a Regional Reliability Standard.
- VAR-501-WECC-1 — Power System Stabilizer ensures that Power System Stabilizers (PSS) on synchronous generators shall be kept in service, which far exceeds the specificity in the continent-wide NERC Reliability Standard, VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules.
- No challenges were made by commenters that would serve to rebut WECC's presumption of validity.
- NERC also found that WECC adequately addressed the FERC and NERC directives.

Background*:* WECC- VAR-STD-002b.1 — Power System Stabilizer ensures power system stabilizers on generators shall be kept in service at all times, and shall be properly tuned in accordance with WECC requirements. A power system stabilizer is part of the excitation control system of a generator used to increase power transfer levels by improving power system dynamic performance. In the Western Interconnection, System Operating Limits for transmission paths in the bulk power system assume that power system stabilizers are in service to enhance system damping. Therefore in the Western Interconnection, power system stabilizers are only permitted to be out of service under very specific predefined conditions. WECC-VAR-STD-002b.1 contains requirements for power system stabilizers not covered in the continent-wide NERC Reliability Standards thereby satisfying the statutory criteria for consideration as a regional standard.

In its June 8, 2007 Order approving eight WECC Regional Reliability Standards that included WECC- VAR-STD-002b.1, FERC directed WECC to make conforming changes to the standard based on the shortcomings identified in NERC's evaluation of the standard, as follows:

1. Remove the sanctions table that is inconsistent with the NERC Sanction Guidelines and add Violation Risk Factors and Violation Severity Levels; and
2. Conform the standard to the form of NERC Reliability Standards with respect to the effective date, stating it should become effective on the first day of following quarter upon regulatory approval.

Further, FERC supported NERC's conditions for approval that WECC meet its commitment to address the shortcomings over the course of the year.

Proposal VAR-501-WECC-1 — Power System Stabilizer: The proposed Regional Reliability Standard, VAR-501-WECC-1, was submitted to NERC on June 11, 2008 for approval, replacing the

FERC-approved Regional Reliability Standard VAR-STD-002b.1. In processing the proposed Regional Reliability Standard, WECC indicated it used its standards development procedure that existed at the time in accordance with its Regional Delegation Agreement with NERC.

In the request for approval WECC explained that Regional Reliability Standard VAR-501-WECC-1 is more stringent than the continent-wide NERC Reliability Standard VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules. The requirements in VAR-501-WECC-1 ensure that power system stabilizers are in service and the generator provides the proper damping to maintain system stability when generation and transmission outages occur. The NERC Reliability Standard VAR-002-1a requires merely that a Generator Operator notify its Transmission Operator when it removes the power system stabilizer from service and does not limit the amount of time for operating generators without them in service.

The proposed replacement standard, VAR-501-WECC-1, was modified such that it no longer contains the Sanctions Table; includes Violation Severity Levels, Violation Risk Factors, Measures and Time Horizons; conforms the Effective Date format to that of the NERC standards; and conforms the overall format of the standard to that of the NERC Reliability Standards.

In addition to the directed changes, WECC made other modifications to the standard not included in the FERC and NERC directives:

- WECC proposes a defined term for "Commercial Operation" as follows:

  Commercial Operation — Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.

This term is not in the NERC Glossary of Terms and will be added to the glossary as a WECC-specific definition upon approval of VAR-501-WECC-01.

- WECC modified R1 to state that "Generator Operators shall have PSS [power system stabilizers] in service 98% of all operating hours for synchronous generators equipped with PSS…." The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring PSS to be in service provides time for evaluation and to start up generating facilities when Generator Operators respond to unforeseen events.
- WECC modified the power system stabilizer replacement period to 24 months from 15 months to facilitate procurement requirements for nuclear power plants.

NERC 45-Day Posting: Upon WECC board action in April 2008, WECC submitted its seven proposed regional standards to NERC for the required 45-day public posting that took place from April 4–May 20, 2008. The proposed Regional Reliability Standards received one minor comment during the NERC posting. WECC supplied NERC with its response to this comment on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received.

NERC Evaluation: In accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*, approved by the Regional Reliability Standards Working Group, NERC provided its evaluation of the proposed standard VAR-501-WECC-1 to WECC on July 30, 2008 (Appendix 4). In this report NERC made several recommendations to the proposed standard VAR-501-WECC-1 to which WECC responded in an August 18, 2008 letter (Appendix 5):

- NERC suggested WECC add a table containing the Violation Severity Levels to conform to the NERC Reliability Standards. WECC agreed that the proposed Violation Severity Levels in VAR-501-WECC-1 are inconsistent in format with that of the NERC Reliability Standards.
- NERC noted the proposed standard VAR-501-WECC-1 specified in R1 that Generator Operators shall have power system stabilizers in service 98 percent of all operating hours. This appears initially to be different than the current requirement WR1 in WECC-VAR-STD-002b-1 which specifies that they are to be in service at all times. WECC clarified in its response to NERC's evaluation (Appendix 5) that the requirement had not been modified but rather was a translation of the existing WECC-VAR-STD-002b-1 Levels of Non-compliance into the requirements of VAR-501-WECC-01.
- In addition, NERC expressed concern with VAR-501-WECC-01 R1.1 that the standard excludes the hours for power system stabilizer operation attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC explained there is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufacturers recommend placing the power system stabilizer in-service). Operating at low megawatt levels makes the power system stabilizer ineffective. The exclusion below the five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units without penalty for having an out-of-service power system stabilizer per the manufacturer recommendations.

NERC staff believes WECC responded adequately to NERC's suggestions by agreeing to conform the Violation Severity Levels format to that of the NERC Reliability Standards in a revision to the standard. In addition, FERC staff commented on the extension of time proposed in the standard that changes from 15 months to 24 months the time allowed for automatic voltage regulator (AVR) and power system stabilizer replacement. WECC explained that the period of time was lengthened to reflect realistic approval and procurement time frames for this equipment for nuclear power plants in particular.

Supporting Documents

- Appendix 1 — Regional Reliability Standard Submittal Request
- Appendix 2 — Standard Development Roadmap
- Appendix 3 — Consideration of Comments document on NERC's posting of the regional standard
- Appendix 4 — NERC Evaluation of WECC Regional Standards
- Appendix 5 — WECC Response to NERC Evaluation
- Appendix 6 — WECC Response to FERC Comments
- Appendix 7 — WECC Consideration of Comment Reports
- Appendix 8 — WECC Standards Drafting Team
- Appendix 9 — WECC Balloting

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standard Submittal Request

Region: Western Electricity Coordinating Council

Regional Standard Number: VAR-501-WECC-1

Regional Standard Title: Power System Stabilizer

Date Submitted: June 10, 2008

Regional Contact Name: Steven L. Rueckert

Regional Contact Title: Director of Standards

Regional Contact Telephone Number: (801) 582-0353

Request (check all that apply):

☒ Approval of a new standard
☐ Revision of an existing standard
☒ Withdrawal of an existing standard
☐ Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

☒ Yes April 16, 2008
☐ No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:

The purpose of this standard is to create a permanent replacement standard for VAR-STD-002b-1. VAR-501-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when VAR-STD-002b-1 was approved as a NERC reliability standard.

Concise statement of the justification of the request:

To page 1 resource links

The VAR-501-WECC-1 regional reliability standard is more stringent than the continent-wide reliability standard (Standard VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules). A power system stabilizer is part of the excitation control system of a generator used to increases power transfer levels by improving power system dynamic performance. In the Western Interconnection, System Operating Limits for transmission paths in the Bulk Electric System assume that Power System Stabilizers are in service to enhance system damping. The requirements in VAR-501-WECC-1 are to ensure that the generator provides the proper damping to maintain system stability when generation and transmission outages occur. Therefore in the Western Interconnection, Power System Stabilizers are only permitted to be out of service under very specific predefined conditions. The NERC VAR-002-1a only requires that a generator operator notify its transmission operator when it removes the Power System Stabilizer from service and does not limit the amount of time for operating generators without Power System Stabilizer in service.

Other — please attach or include as separate files:

- The text of the regional reliability standard in MS Word format that:
    - has either been, or is anticipated to be, approved by the regional entity's board, and
    - is in a format consistent with the NERC template for reliability standards.
- An implementation plan.
- The regional entity standard drafting team roster.
- The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.
- The final ballot results, including a list of significant minority issues that were not resolved, and
- For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

Completed Actions	Completion Date
1. Post Draft Standard for initial industry comments	September 26, 2007
2. Drafting Team to review and respond to initial industry comments	November 30, 2007
3. Post second Draft Standard for industry comments	November 30, 2007
4. Drafting Team to review and respond to industry comments	January 25, 2008
5. Post Draft Standard for Operating Committee approval	January 25, 2008
6. Operating Committee ballots proposed standard	March 6, 2008
7. Post Draft Standard for WECC Board approval	March 12, 2008
8. Post Draft Standard for NERC comment period	April 14, 2008
9. WECC Board approved proposed standard	April 16, 2008
10. NERC comment period ended	May 20, 2008
11. Drafting Team to review and respond to industry comments	May 30, 2008

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for VAR-STD-002b-1. VAR-501-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when VAR-STD-002b-1 was approved as a NERC reliability standard.

In the Western Interconnection, System Operating Limits for transmission paths in the Bulk Electric System assume that Power System Stabilizers are in service to enhance system damping. The requirements in VAR-501-WECC-1 are to ensure that the generator provides the proper damping to maintain system stability when generation and transmission outages occur.

This version of the VAR-501-WECC-1 standard is for NERC Board of Trustee ballot. The WECC Board of Directors approved the standard April 16, 2008. WECC Operating Committee approved the standard March 6, 2008. The WECC Board of Directors and Operating Committee request that the NERC Board of Trustees approve the VAR-501-WECC-1 Standard as a permanent replacement standard for VAR-STD-002b-1 and that the NERC Board of Trustees submits the standard to FERC for approval and replacement of VAR-STD-002b-1.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Submit NERC Board approval request	June 2008
2. Request FERC approval	June 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

Commercial Operation - Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.

A. Introduction

1. **Title:** **Power System Stabilizer (PSS)**
2. **Number:** VAR-501-WECC-1
3. **Purpose:** To ensure that Power System Stabilizers (PSS) on synchronous generators shall be kept in service.
4. **Applicability**

   4.1. Generator Operators

5. **Effective Date:** On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Generator Operators shall have PSS in service 98% of all operating hours for synchronous generators equipped with PSS. Generator Operators may exclude hours for R1.1 through R1.12 to achieve the 98% requirement. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R1.1. The synchronous generator operates for less than five percent of all hours during any calendar quarter.

R1.2. Performing maintenance and testing up to a maximum of seven calendar days per calendar quarter.

R1.3. PSS exhibits instability due to abnormal system configuration.

R1.4. Unit is operating in the synchronous condenser mode (very near zero real power level).

R1.5. Unit is generating less power than its design limit for effective PSS operation.

R1.6. Unit is passing through a range of output that is a known “rough zone” (range in which a hydro unit is experiencing excessive vibration).

R1.7. The generator AVR is not in service.

R1.8. Due to component failure, the PSS may be out of service up to 60 consecutive days for repair per incident.

R1.9. Due to a component failure, the PSS may be out of service up to one year provided the Generator Operator submits documentation identifying the need for time to obtain replacement parts and if required to schedule an outage.

R1.10. Due to a component failure, the PSS may be out of service up to 24 months provided the Generator Operator submits documentation identifying the need for time for PSS replacement and to schedule an outage.

R1.11. The synchronous generator has not achieved Commercial Operation.

R1.12. The Transmission Operator directs the Generator Operator to operate the synchronous generator, and the PSS is unavailable for service.

R2. Generator Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.12. *[Violation Risk Factor: Low] [Time Horizon: Operations Assessment]*

C. Measures

M1. Generators Operators shall provide quarterly reports to the compliance monitor and have evidence for each synchronous generator of the following:

- o The number of hours the synchronous generator was on line.

- The number of hours the PSS was out of service with generator on line.
- The PSS in service percentage
- If excluding PSS out of service hours as allowed in R1.1 through R1.12, provide:
  - The number of hours excluded, and
  - The adjusted PSS in-service percentage.

M2. If excluding hours for R1.1 through R1.12, provide:

- The date of the outage
- Supporting documentation for each requirement that applies

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be a calendar quarter.

1.3 Data Retention

The Generator Operators shall keep evidence for Measures M1 and M2 for three years plus current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

1.4.1 The sanctions shall be assessed on a calendar quarter basis.

1.4.2 If any of R1.2 through R1.12 continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. For example, in R1.8 if the 60 day repair period goes beyond the end of a quarter, the repair period does not reset at the beginning of the next quarter.

1.4.3 When calculating the adjusted in-service percentage, the PSS out of service hours do not include the time associated with R1.1 through R1.12.

1.4.4 The standard shall be applied on a generating unit by generating unit basis (a Generator Operator can be subject to a separate sanction for each non-compliant synchronous generating unit or to a single sanction for multiple machines that operate as one unit).

2. Violation Severity Levels

2.1. Lower: There shall be a Lower Level of non-compliance if the following condition exists:

2.1.1. PSS is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.2. Moderate: There shall be a Moderate Level of non-compliance if the following condition exists:

2.2.1. PSS is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.3. High: There shall be a High Level of non-compliance if the following condition exists:

2.3.1. PSS is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.4. Severe: There shall be a Severe Level of non-compliance if the following condition exists:

2.4.1. PSS is in service less than 70% of all hours during which the synchronous generating unit is on line for each calendar quarter.

3. Violation Severity Levels for R2

3.1. Lower: There shall be a Lower Level of non-compliance if documentation is incomplete with any requirement R1.1 through R1.12.

3.2. Moderate: There shall be a Moderate Level of non-compliance if the Generator Operator does not have documentation to demonstrate compliance with any requirement R1.1 through R1.12.

3.3. High: Not Applicable

3.4. Severe: Not Applicable

E. Regional Differences

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002b-1	

Appendix 3

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Comment Report Form for WECC Standard VAR-501-WECC-1 — Power System Stabilizer

The VAR-501-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the VAR-501-WECC-1 Standard. This Standard was posted for a 45-day public comment period from April 4, 2008 through May 20, 2008. NERC distributed the notice for this posting on April 7, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were two sets of comments from three companies representing four of the ten Industry Segments as shown in the table on the following pages.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the Standard can be viewed in their original format at:

http://www.nerc.com/~filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Manager of Regional Standards, Stephanie Monzon at Stephanie.monzon@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is described in the NERC Regional Reliability Standards Development Procedure: ftp://www.nerc.com/pub/sys/all_updl/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Denise Koehn	Bonneville Power Administration (BPA)	✓		✓		✓	✓				
2.	Annette Bannon, Tom Olson, and Gus Wilkins	PPL Generation, LLC, PPL Montana, LLC					✓	✓				

Index to Questions, Comments, and Responses

1. **Was the WECC Standard VAR-501-WECC-1 – Power System Stabilizer developed in a fair and open process, using the Process for Developing and Approving WECC Standards?**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn	X		
Response: Thank you.			
Annette Bannon, Tom Olson, and Gus Wilkins			
Response:			

2. **Does the WECC Standard VAR-501-WECC-1 – Power System Stabilizer pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn		X	
Response: Thank you.			
Annette Bannon, Tom Olson, and Gus Wilkins			
Response:			

3. **Does the WECC Standard VAR-501-WECC-1 – Power System Stabilizer pose a serious and substantial threat to public health, safety, welfare, or national security?**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn		X	
Response: Thank you.			
Annette Bannon, Tom Olson, and Gus Wilkins			
Response:			

4. **Does the WECC Standard VAR-501-WECC-1 – Power System Stabilizer pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn		X	
Response: Thank you.			
Annette Bannon, Tom Olson, and Gus Wilkins	X		PPL suggests that the actual reliability standard (not WECC policies) should include an explicit description of which units must have PSS's (including which units are grandfathered), and this criteria should be subject to change in accordance with the standard development process.
Response: The VAR-501-WECC-1 applies to generators equipped with power system stabilizers. The drafting team implemented the VAR-501-WECC standard similar to the VAR-STD-002b-1 standard and did not include a description of which units are required to have power system stabilizers. The drafting team did not identify a need to permit a grandfather provision for the power system stabilizer standard as it only applies to generators equipped with power system stabilizers. The drafting team will recommend that when the VAR-501-WECC-1 standard is reviewed, the new drafting team should address this comment.			

5. **Does the WECC Standard VAR-501-WECC-1 – Power System Stabilizer meet at least one of the following criteria?**

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Commenter	Yes	No	Comment
Denise Koehn	X		
Response: Thank you.			
Annette Bannon, Tom Olson, and Gus Wilkins			
Response:			

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NERC Evaluation of Western Electricity Coordinating Council (WECC) Regional Standards

Executive Summary
July 30, 2008

On June 11, 2007, the WECC submitted the following seven regional standards for NERC evaluation to replace eight original WECC regional standards approved by NERC and FERC in 2007:

- BAL-002-WECC-1 — Contingency Reserves,
- FAC-501-WECC-1 — Transmission Maintenance,
- IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief,
- PRC-004-WECC-1— Protection System and Remedial Action Scheme Misoperation,
- TOP-007-WECC-1 — System Operating Limits,
- VAR-002-WECC-1 — Automatic Voltage Regulators and
- VAR-501-WECC-1 — Power System Stabilizer

NERC posted these seven proposed regional standards for a 45-day public posting beginning April 4–May 20, 2008. The standards received several comments during the NERC public posting. WECC supplied NERC with its responses to the comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting. WECC submitted these standards for NERC evaluation on June 11, 2008.

In accordance with NERC's *Rules of Procedure* and the *Regional Reliability Standards Evaluation Procedure* approved by the Regional Reliability Standards Working Group, NERC performed a review of the WECC proposed standards. The intent of this document is to provide WECC with NERC's feedback regarding their regional standards.

In this review, NERC presents a summary of observations for each proposed WECC regional standard. In Appendix A, NERC includes a redlined copy of each proposed regional standard with detailed comments included. NERC believes WECC has satisfied its procedural obligations as outlined in Appendix C of its Regional Delegation Agreement. However, NERC offers concerns and suggestions regarding several of the proposed regional standards that are discussed below.

Summary of Findings

BAL-002-WECC-1 — Contingency Reserves

In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

1. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

2. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

   R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

   R1.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

   R1.2. Capable of fully responding within ten minutes.

   In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

3. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

4. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

FAC-501-WECC-1 — Transmission Maintenance

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

1. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

2. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

1. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

2. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

3. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

1. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

2. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

3. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

4. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

TOP-007-WECC-1 — System Operating Limits

1. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

2. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

VAR-002-WECC-1 — Automatic Voltage Regulators

1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

   More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

VAR-501-WECC-1 — Power System Stabilizer

1. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a

justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

Conclusion

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC's Response to NERC's Comments
August 13, 2008
Draft

INTRODUCTION

WECC appreciates NERC staff's evaluation of the proposed WECC Regional Reliability Standards (RRSs) in accordance with NERC's Regional Reliability Standards Evaluation Procedure. These proposed WECC RRSs were developed as permanent replacements for the eight WECC Tier 1 RRSs that previously were approved by NERC and FERC. WECC asserts that the seven proposed standards contain all the performance elements of a Reliability Standard that are contained in the NERC Reliability Standards Development Procedure. In addition, the seven proposed standards address and implement the refinements directed by FERC's order on June 8, 2007 (see FERC Docket No.
RR07-11-000) and requested by NERC in its letter dated January 9, 2007. Finally, these proposed standards implement refinements to the approved WECC Tier 1 RRSs which were recommended during the previous expedited direct translation standard development processes.

The attached WECC responses individually address each NERC comment. However, many of the comments submitted by NERC staff relate to refinements that NERC has made to the format of its Reliability Standard Template. These refinements have not been formally approved by NERC, nor have they been transmitted to the regions for comment or additional information, and were therefore unavailable to WECC during the development process. Consequently, WECC has determined not to reopen the standards development process at this stage to address these non-substantive formatting concerns. In addition, during the standards development process, WECC staff twice requested that NERC staff review the proposed WECC standards. WECC did this to ensure that the WECC standard drafting teams were complying with NERC's Regional Reliability Standards Evaluation Procedure as well as its Reliability Standards Development Procedure. NERC did not perform the evaluation of these proposed standards until WECC had completed its Process for Developing and Approving WECC Standards. WECC intends to implement the requested formatting refinements and any potential FERC-directed changes during the next revision of these standards or the next FERC compliance filing.

The proposed WECC RRSs were considered and adopted pursuant to the Process for Developing and Approving WECC Standards. Unless they are approved in their current form, WECC will have to reinitiate the entire process. The consequences of rejecting these WECC RRSs in their entirety would be counterproductive to reliability in the Western Interconnection.

The proposed WECC RRSs will enhance reliability in the Western Interconnection and they will significantly improve the existing eight WECC RRSs because they:

1. Implement ordered NERC and FERC refinements to the existing standards ordered;
2. Eliminate conflicting NERC and WECC requirements contained in the existing RRSs;
3. Include all the Performance Elements of a Reliability Standard;
4. Clarify existing WECC RRSs;
5. Align better with NERC's Functional Model, and
6. Address industry stakeholder concerns.

Therefore, WECC requests the NERC staff recommend approval of these standards to the NERC Board and FERC.

WECC's responses to NERC's initial evaluation are provided in Attachment 1.

Attachment 1

NERC's Written Comments
July 30, 2008
WECC's Written Responses
August 13, 2008

Summary of Findings

BAL-002-WECC-1 — CONTINGENCY RESERVES

NERC COMMENT:
In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

5. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

WECC RESPONSE:
1. The requirements in the BAL-002-WECC-1 Standard as written are clear. Industry stakeholders did not submit any comments questioning the clarity of the standard, nor did they identify a need for an equation. The drafting team does not believe there is any ambiguity in the requirements.

NERC COMMENT:
6. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

R2. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

R2.2. Capable of fully responding within ten minutes.

WECC RESPONSE:
2. The drafting team wrote the BAL-002-WECC-1 Standard to permit load, Demand-Side Management (DSM), generation, or another resource technology that qualifies as Spinning Reserve or Contingency Reserve to be used as such. In the case of DSM, the declared amount would be required to respond automatically to frequency deviations and be capable of fully responding in 10

minutes. Loads and DSM are not allowed as Spinning Reserve because it is not permitted by the NERC Spinning Reserve definition. NERC requires that the BAL-002-WECC-1 Standard drafting team use NERC's Spinning Reserve definition. If NERC were to modify its Spinning Reserve definition to allow frequency responsive load tripping as part of a Balancing Authority's DSM, then its use would be permitted under the requirements of the BAL-002-WECC-1 Standard as proposed.

NERC COMMENT (continued):

In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

WECC RESPONSE (continued):

DSM that is deployable within 10 minutes is a subset of Interruptible Load. Interruptible load is defined in requirement R3.2 as an acceptable type of Contingency Reserve. As described previously, if NERC modifies its Spinning Reserve and Interruptible Load definitions, then it would be clear that qualifying DSM is permitted as part of Spinning and Contingency Reserves.

NERC COMMENT:

7. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

WECC RESPONSE:

3. The drafting team wrote a paper titled "WECC Standard BAL-002-WECC-1 Contingency Reserves" that provides an explanation supporting the modification. The paper was included as part of the standards approval package filed on June 11, 2008 with NERC.

NERC COMMENT:

8. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

WECC RESPONSE:

4. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

FAC-501-WECC-1 — TRANSMISSION MAINTENANCE

NERC COMMENT:

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

3. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

WECC RESPONSE:

1. "Transmission Facilities" is not a NERC-defined term in the NERC "Glossary of Terms Used in Reliability Standards" document, although "Transmission" and "Facility" are. The standard drafting team did not capitalize "transmission facilities" because it believes that the combination of these two defined terms was too limiting. WECC recognizes that this may create confusion and it proposes to address this issue during the next revision of these standards or the next FERC compliance filing.

NERC COMMENT:

4. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

2. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>IRO-006-WECC-1 — QUALIFIED TRANSFER PATH UNSCHEDULED FLOW (USF) RELIEF</u>

NERC COMMENT:

4. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

WECC RESPONSE:

1. The proposed IRO-006-WECC-1 Standard contains all the key reliability requirements and technical elements from the Unscheduled Flow Mitigation Plan (UFMP) that were included in IRO-STD-006-0. The proposed IRO-006-WECC-1 Standard uses NERC's Functional Model terminology to mitigate unscheduled flow <u>during the next operating hour</u>. It is not necessary to reference the remainder of the UFMP because the remaining items contain procedural requirements explaining "how," not "what." The proposed IRO-006-WECC-1 Standard includes requirements to reduce schedules, which then require adjustments to generation patterns. This prevents potential overloads <u>during the next operating hour</u>. Importantly, the requirements for mitigation of an actual (real-time) overload are contained in TOP-007-WECC-1.

NERC COMMENT:

5. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC

proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

WECC RESPONSE:

2. WECC acknowledges the difference between the NERC and WECC definitions for Transfer Distribution Factor (TDF). This is caused by the differences between the Eastern Interconnection Transmission Loading Relief process and the Western Interconnection UFMP. This difference in definitions exists even today between the existing FERC-approved IRO-STD-006-0 Standard and the NERC Glossary. Rejecting the proposed standard will not resolve this difference. WECC will work with NERC to resolve this and intends to make any necessary refinements during the next revision of this standard or the next FERC compliance filing. Despite the difference in the TDF definitions, **the proposed standard corrects a basic difference between the existing FERC-approved IRO-STD-006-0 Standard, which places reliability responsibilities upon the Load Serving Entities (LSEs), and the NERC Functional Model.** LSEs do not have the ability to ensure the implementation of the schedule adjustments required in the existing FERC-approved IRO-STD-006-0 Standard.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

5. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>PRC-004-WECC-1 — PROTECTION SYSTEM AND REMEDIAL ACTION SCHEME MISOPERATION</u>

NERC COMMENT:

5. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

WECC RESPONSE:

1. WECC recognizes that the standard drafting team included explanatory text in the requirement section in an attempt to clarify the requirements. However, the duplication does not adversely impact the applicability, clarity, or the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

6. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

WECC RESPONSE:

2. WECC recognizes that the standard drafting team included System Operators and System Protection personnel in the requirements. R1. of PRC-004-WECC-1 states that, **"System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection Systems and RAS operations."** As written the requirement is sufficiently clear and well-defined to be enforceable on the entities in the Western Interconnection. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

7. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

WECC RESPONSE:

3. WECC recognizes that the standard drafting team included explanatory text in the requirement section that might be more appropriately included as a footnote. However, the text clarifies the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

8. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

WECC RESPONSE:

4. The requirements in the PRC-004-WECC-1 Standard are clearly written. Industry stakeholders did not submit any comments questioning the clarity of the standard. The alternative standard drafting formats or language used in this standard, are applicable exclusively to the Western Interconnection. These stylistic differences do not affect others and should not be a consideration for NERC approval.

TOP-007-WECC-1 — SYSTEM OPERATING LIMITS (SOLs)

NERC COMMENT:

3. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

WECC RESPONSE:

1. In the Western Interconnection, SOLs are designed so that during steady-state operations, with all lines in service, the system is at least two contingencies away from cascading. Therefore, exceeding an SOL for the 40 major paths identified in the TOP-007-WECC-1 Standard would not typically qualify as an Interconnection Reliability Operating Limit (IROL) under NERC's TOP-007-0 Standard. The standard drafting team created the TOP-007-WECC-1 Standard to limit the amount of time that a SOL may be exceeded for these very important paths, which makes the TOP-007-WECC-1 Standard more stringent than the NERC standard.

NERC COMMENT:

4. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

WECC RESPONSE:

2. The existing standard created confusion during system operation because system conditions may change the limiting conditions on a path. This is because the limit depends upon whether thermal, stability, or post transient limitations are the limiting factor. In addition, having different response times for paths (and sometimes for the same path depending on current outage conditions), complicates system operation, causing delays in responding to the path overload. This resulted in path operators implementing more drastic actions to respond to a contingency within 20 minutes, which may put the system at greater risk, particularly during heavy load periods such as summer. The standard drafting team determined that changing the standard from a 20-minute to a 30-minute response time is insignificant in terms of the probability of a next contingency occurring. Moreover, the drafting team believes that following a system disturbance, the system operators will be better able to identify what generation to ramp in order to be effective in mitigating the overload. This will also allow them to coordinate with others before implementing the generation ramps. Therefore, the simplification of the standard to one consistent 30-minute period improves reliability. It is important to recognize that in spite of extending the recovery period, the refinement should improve system reliability.

VAR-002-WECC-1 — AUTOMATIC VOLTAGE REGULATORS (AVRs)

NERC COMMENT:

4. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-002-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002a-1 Standard. The 98 percent in Requirement R1. of

VAR-002-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002a-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring the AVR to be in service provides for time to start up generating facilities. It also allows for evaluation when the Generator Operators respond to unforeseen events.

NERC COMMENT (continued):
More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

WECC RESPONSE (continued):
NERC VAR-002-1a R1. permits the Generator Operator to operate in different modes by simply notifying the Transmission Operator. There are no restrictions on the length of time or reasons for operating in other modes. The WECC 1996 outage reports identified the lack of reactive support from generators with AVRs operating in modes other than voltage control as one of the causes of the WECC 1996 outages. The VAR-002-WECC-1 Standard limits the reasons and time for operating a generator without the AVR in service and controlling voltage, therefore it is more stringent than the NERC VAR-002-1a Standard.

NERC COMMENT

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the AVR in service). The use of peaking units adds to overall system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>VAR-501-WECC-1 — POWER SYSTEM STABILIZER (PSS)</u>
NERC COMMENT:

4. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as

the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-501-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002b-1 Standard. The 98 percent in Requirement R1. of VAR-501-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002b-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring PSS to be in service provides time for evaluation and to start up generating facilities when Generator Operators respond to unforeseen events.

NERC COMMENT:

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the exiting standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the PSS in-service). Operating at low megawatt levels makes the PSS ineffective. The use of peaking units adds to over-all system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture PSS in service recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes that the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

(NERC) CONCLUSION

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC RESPONSE

WECC appreciates the opportunity to discuss NERC staff's initial evaluation and report in conference calls on August 4 and 5, 2008 and to provide the written clarifications and responses contained herein. We trust that WECC's responses, along with all the supporting documentation contained in WECC's submissions, provide the NERC staff a comprehensive basis for recommending NERC Board of Trustees approval of all proposed standards. Please direct any questions relating to WECC's response to WECC Director of Standards, Steve Rueckert at steve@wecc.biz or (801) 883-6878.

WECC Responses to FERC Staff Concerns and Questions
Regarding the Proposed WECC Tier 1 Standards
June 17, 2008

I. Contingency Reserves — BAL-002-WECC-1

A. Period of Contingency Reserve Restoration: Does the proposed standard modify the current standard to provide a longer period of time of 90 minutes rather than 60 minutes?

Yes, the requirement to restore contingency reserves within 60 minutes was eliminated in the proposed standard. The current standard requires the restoration of contingency reserves within the first 60 minutes following an event. By eliminating this requirement in the proposed standard, WECC adopts the NERC default standard that requires the restoration of contingency reserves within 90 minutes from the end of the disturbance recovery period.[2]

The 60 minute restoration period required by the current standard was developed and used under a manual interchange transaction structure among vertically integrated utilities. As the electric utility industry restructured, there has been a substantial increase in the number of market participants and interchange transactions.[3] To accommodate the increase in number of interchange transactions and market participants an electronic tagging system was implemented in the Western Interconnection. The adoption of an electronic tagging system that accommodates multiple market participants and a large number of interchange transactions made the current mid-hour reserve restoration more cumbersome and made the inappropriate rejection of reserve restoration transactions more likely because such transactions are outside the electronic tagging cycle.

Eliminating the 60 minute reserve restoration requirement and adopting the NERC requirements results in more efficient communication among Balancing Authorities (BAs) because it aligns the restoration of contingency reserves with the electronic tagging system approval cycle. Adopting the NERC contingency reserve restoration requirements reduces the potential for reserve transactions being inappropriately rejected resulting in improved communication among BAs resulting in improved reliability.

B. Shedding of Firm Load: Does the proposed standard change the treatment of the shedding of firm load compared to the current standard?

No, both standards allow for the shedding of firm load under limited circumstances. The addition of requirement R3.4 in the proposed standard clarified the process. During capacity and energy emergencies, a BA or Reserve Sharing Group (RSG) may use load as non-spinning reserves; that is BAs and RSGs will not drop load to maintain their non-spinning reserve requirement. Rather they will use load as part of their non-spinning contingency reserves.

[2] See NERC Standard BAL-002-0 Requirement R6 and WECC Standard BAL-STD-002-0 WR1.d.
[3] Balancing Authorities in the Western Interconnection approve between 2,500 and 4,500 interchange transactions per day.

This standard emphasizes the responsibility of serving customer load first while at the same time protecting the reliability of the Western Interconnection. Even during capacity and energy emergencies, BAs and RSGs are required to comply with the spinning reserve requirements.

C. Deliverability of Contingency Reserves: Does the proposed standard require that contingency reserves be deliverable?

Yes, nothing has changed with respect to the deliverability of contingency reserves.

D. Interruptible Imports: In the current standard the sink BA is required to carry an additional amount of contingency reserves equal to the amount of interruptible imports. Does the proposed standard have the same requirement?

Yes, the term interruptible imports was eliminated from the proposed standard. It was replaced with the added requirement R1.2 which requires that "If the Source BA designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink BA shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s)." This is an improvement from the current standard because it eliminates ambiguity in the term interruptible imports.

E. Demand Side Management: Did the drafting team comply with FERC Order 693 to explicitly allow demand-side management (DSM) to be used for reserves?

Yes, DSM that is deployable within 10 minutes is a subset of interruptible load. Interruptible load is defined in requirement R3.2 as an acceptable type of contingency reserve.

II. Qualified Transfer Path Unscheduled Flow Relief- IRO-006-WECC-1

A. Is the proposed standard intended to address an actual (real time) overload situation?

No, a different standard TOP-007-WECC-1 covers actual (real time) overload situations. The proposed IRO-006-WECC-1 standard includes requirements to reduce schedules, which requires adjustments to generation patterns, to prevent potential overloads during the next operating hour.

B. Should the Unscheduled Flow Mitigation Plan (UFMP) be incorporated in the IRO-006-WECC-1 by reference?

No, the key reliability portions from the UFMP are incorporated in the proposed standard. It is not necessary to reference the remainder of the UFMP.

C. Does the WECC UFMP need to be updated?

Yes, WECC has initiated the process of updating its UFMP.

III. System Operating Limits—TOP-007-WECC-1

A. Could the language in TOP-007-WECC-1 allow for the system to be less than two contingencies away from cascading and more specifically one contingency away from cascading?

No, the proposed standard is designed such that path operations must be at least two contingencies away from cascading during steady state operations. In real time operations when System Operating Limits (SOL) are exceeded for periods not to exceed 30 minutes, there may be system conditions that are less than two contingencies away from cascading.

B. Could IRO-005-2 Requirements R3 and R5 be interpreted that the power system is being operated two contingencies away from a cascading outage while WECC TOP-007-WECC-1 requirement R1 results in the power system being operated one contingency away from a cascading outage?

No, IRO-005-2 requirements R3 and R5 are consistent with the requirements in TOP-007-WECC-1. In the Western Interconnection SOLs are developed in such a manner that the system operation is at least two contingencies away from a cascading failure. This is implicit in the identification of the SOL derivation. If, however, there is a flow that exceeds the SOL, Transmission Operators (TOP) and Reliability Coordinators (RC) must take proactive immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the transmission path exceed the SOL for more than 30 minutes, thus protecting the system from potential cascading for a subsequent contingency.

C. Do SOL changes within the hour extend the time for compliance?

No, SOL changes within an operating hour do not extend the time for compliance.

IV. Automatic Voltage Regulators and Power System Stabilizers – VAR-002-WECC-1 and VAR-501-WECC-1

A. How does VAR-002-WECC-1 coordinate with the new NERC Standard VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules?

VAR-002-WECC-1 contains specific, more restrictive, requirements on generator operators regarding the operation of Automatic Voltage Regulators (AVR) that are not contained in the NERC Standard VAR-002-1. The reasons for these more restrictive requirements are to support transfer capabilities in the Western Interconnection and to address the insufficient supply of reactive power identified as a cause of the 1996 system disturbances in the Western Interconnection. The drafting team designed the VAR-002-WECC-1 Standard to limit the reasons for operating AVRs in a mode that does not control voltage and the amount of time permitted for such operations. Generator operators are still required to comply with all the requirements contained in NERC VAR-002-1.

B. Are Power System Stabilizers (PSS) included in either of these standards?

Yes, VAR-501-WECC-1 contains requirements regarding the in-service operation of PSS.

C. Why were the AVR and PSS replacement period extended to two years from 15 months?

The amount of time to replace AVR and PSS was lengthened to accommodate the approval and procurement time frames for AVR and PSS for nuclear power plants, which are two years.

V. Transmission Maintenance – FAC-501-WECC-1

A. Does the FAC-501-WECC-1 standard reduce the number of lines that are subject to this standard to the SOL limiting factors from the lines and facilities associated with the 40 paths thereby reducing the obligation for maintenance?

No, there is no change in the number of lines or facilities subject to the proposed FAC-501-WECC-1 standard.

CONSIDERATION OF COMMENTS FOR VAR-501-WECC-1 — POWER SYSTEM STABILIZER
COMMENTS WERE DUE JANUARY 2, 2008
JANUARY 24, 2008

The VAR-501-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the WECC VAR-501-WECC-1 Standard. This Standard was posted for a 30-day public comment period from November 30, 2007 through January 2, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard by posting comments on the WECC website. There were four sets of comments from four companies.

In this 'Consideration of Comments' document, stakeholder comments have been organized so that it is easier to see the responses associated with each comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Steve Rueckert at 801-582-0353 or at steve@wecc.biz. In addition, there is a WECC Appeals Process.

The NERC has designed the structure of reliability standards to contain requirements, measures, and compliance. Recommendations such as combining the compliance period into the requirement do not conform to the structure for a standard. The drafting team believes that it should follow the structure for a standard and did not implement these refinements.

Comments and Responses

CEA (used in Section D.1.1) has been well established as the abbreviation for Canadian Electrical Association. This will be quite confusing for those North of the border if adopted as the abbreviation for compliance enforcement authority.

Blaine Beisiegel

Reply: Thank you for your comment. NERC recommended use of the term Compliance Enforcement Authority in continent wide and regional standards. The drafting team removed CEA.

In R1, I would like the committee to entertain clarification of the 98% statement. I recommend "Generator Operators shall have PSS in service 98% of all operating hours for synchronous generators equipped with PSS, unless one of the following applies." be replaced with "Generator Operators operating synchronous generators with PSS, shall have the PSS in service 98% of all operating hours of the specified quarterly reporting period unless one of the following applies."

Reply: The drafting team made refinements to the purpose statement, R1, M1 and M2 to make the application of R1 clear. Quarterly compliance is included in the violation severity levels and under compliance monitoring period.

In R2, the statement should better reflect the R1 Requirement, and not the subrequirements. I recommend replacing "Generator Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.12." with "Generator Operators shall maintain documentation identifying all hours the PSS was not in service, and the verification for any exceptions permitted under requirement R1."

Reply: The drafting team made refinements to the purpose statement, R1, M1 and M2 to make the application of R2 clear.

I recommend adding another M1 sub requirement for the total hours for the reporting quarter.

Reply: The total hours in the reporting quarter is not needed to determine compliance.

Please check that Section D 1.1 is consistent with the FM. I would recommend the use of the proposed Ver4 language.

Reply: NERC has not posted Functional Model Version 4 on its website. Compliance Enforcement Authority is not in version 3.

In Section D 1.4.4 "The standard shall be applied on a machine-by-machine basis (a Generator Operator can be subject to a separate sanction for each noncompliant synchronous generator)."

This can be a significant problem for entities who utilize a single PSS to control multiple units. If a station has one PSS for 10 individual generators, every violation could be interpreted to be multiplied X10. This is not the intent, and could set an inappropriate level of sanction. This standard is not to establish what machines have PSS, but how to operate machines that have PSS.

This item needs to be corrected, clarified, or removed.

Reply: The drafting team made refinements to Section 1 1.4.4 making the standard applicable on a generating unit basis. This means multiple machines that operate as a single unit would be subject to one sanction.

Kevin Conway, GCPUD

Considerations for VAR-[501]-WECC-1

Comment on R1.9 and R1.10

It would seem to simplify the standard if these were combined and the 15 month provision retained. In both exceptions, documentation must be submitted to explain the need to have the [PSS] out of service. It is not clear why from system reliability and performance standard perspective, there is a need to distinguishing between replacement parts or system replacement.

Crystal Musselman

Reply: The drafting team extended the time for PSS replacement to 24 months to accommodate design and procurement especially for nuclear units. There is a distinction between the time required to repair a PSS versus replacement.

The Alberta Electric System Operator (AESO) appreciates the opportunity to comment and would like to offer the following:

- The AESO currently reports PSS data to the WECC on behalf of all Generator Operators in Alberta, instead of each GOP reporting individually.

- It may be worthwhile to review how and if R1.1 fit in the overall R1 requirement together with the other listed "exceptions." It would seem logical, and R1 does seem to imply that, if a generator was operated for less than 5% of time in a calendar quarter, then the generator (versus the time period when PSS was not in service) is to be excluded from the 98% requirement. However, the wording in R1 doesn't quite say that literally. Please review and revise as required.

Thank you.

Anita Lee, P. Eng.
Manager, Operating Policies and Procedures
Alberta Electric System Operator

Reply: The drafting team made refinements to R1 to clarify the requirement. If the unit does not operate five percent or more of all hours during a quarter, the hours the unit operated without PSS may be excluded from the in service percentage calculation.

DRAFTING TEAM FOR VAR-002-WECC-1 AND VAR-501-WECC-1

FIRST NAME	LAST NAME	COMPANY
Baj	Agrawal	Arizona Public Service Company
John	Amos	Siemens Power Generation, Inc.
Greg	Anderson	Southern California Edison
Phillip	Anderson	Idaho Power Company
Waylon	Bowers	US Army Corps of Engineers
Karl	Bryan	US Army Corps of Engineers
Guy	Colpron	Idaho Power Company
Thomas	Foster	Reliant Energy - Ormond Beach Generation Station
George	Girgis	US Department of the Interior
Daniel	Hansen	Reliant Energy
Jerry	Smith	Arizona Public Service Corporation
Ken	Wilson	Western Electricity Coordinating Council
Shane	Kronebusch	British Columbia Hydro
Greg	Lange	Public Utility District No. 2 of Grant County
James	Murphy	Bonneville Power Administration
F.	Okapal	PacifiCorp East
Richard	Padilla	Pacific Gas and Electric Company
Paul	Rice	Western Electricity Coordinating Council
Gerry	Sauve	US Army Corp

OPERATING COMMITTEE

VAR-501-WECC-1

SP - State and Provincial
IS - Interested Stakeholder
TC - Transmission Customer
TP - Transmission Provider

Name of Organization	Name of Voting Member	Voting Class	YES	NO	Abstain
Aquila Networks-WPC (WPE)	Al Logan	TC			X
Arizona Public Service (AZPS)	David Hansen	TC	X		
Basin Electric Power Cooperative (BEPC)	Becky Kern	TC			X
Bear Energy LP (BEAR)	Jeff Winkler (alternate)	TC	X		
Bonneville Power Administration-Power Bus Line (BPAP)	Fran Halpin	TC	X		
BP Energy Company	Julie Martin	TC			X
British Columbia Hydro and Power Authority (BCHA)	Clement Ma	TC	X		
California Department of Water Resources (CDWR)	Glenn Solbert	TC	X		
Calpine Corporation (CALP)	Frank Obertance	TC	X		
Dynegy, Inc. (DYN)	Brian Theaker	TC	X		
Eugene Water & Electric Board (EWEB)	Dean Ahlsten	TC	X		
Fortis Energy Marketing & Trading Group (FEMT)	Jay Alexander	TC	X		
FPL Energy LLC (FPLE)	Mark J. Smith	TC	X		
Gila River Power, L.P. (PGR)	Kenneth Parker	TC			X
Great Basin Transmission, LLC (GBT)	Ali Amirali	TC		X	
Mirant Americas, Inc. (MIR)	John Stout	TC	X		
Morgan Stanley Capital Group Inc.	Patrick Murray (alternate)	TC	X		
Northern California Power Agency (NCPA)	Fred Young	TC	X		
NRG Power Marketing, Inc. (NRG)	Robert Bailey	TC	X		
Pacific Gas & Electric (PG&E)	Joe Minkstein	TC	X		
PacifiCorp (PACM)	John Apperson	TC	X		
Portland General Electric (PGE)	John Jamieson (alternate)	TC			X
Powerex (PWX)	Mike Goodenough	TC			X
PPL EnergyPlus, LLC (PPLE)	John Cummings (Alternate)	TC		X	
PPM Energy, Inc. (PPM)	Diana Scholtes (alternate)	TC	X		
Public Service Company of Colorado (PSC)	Steve Buening	TC	X		
Public Service Company of New Mexico (PNM)	David Miller	TC	X		
Public Utility District No. 1 of Chelan County (CHPD)	Hugh Owen	TC	X		
Public Utility District No. 2 of Grant County (GCPD)	Greg Lange	TC	X		
Puget Sound Energy, Inc. (PSE)	Joe Hoerner (alternate)	TC			X
Reliant Energy, Inc. (REI)	Thomas J. Bradish	TC	X		
Sacramento Municipal Utility District (SMUD)	Vicken Kasarjian	TC	X		
Seattle City Light (SCL)	Pawel Krupa	TC	X		
Sempra Generation (SER)	Leslie Padilla	TC	X		
Sierra Pacific Resources Transmission (SPR)	Sheryl Torrey	TC	X		
Southern California Edison Company (SCE)	John Pespisa	TC	X		
SUEZ Energy Marketing NA, Inc. (SUEZ)	Caitlan Collins	TC	X		
SWRTA Class 2 Group (SC2G)	Dennis Delaney	TC			X
Tacoma Power (TPWR)	Catherine Leone-Woods	TC	X		
U.S. Bureau of Reclamation (USBR)	Deon Murphy	TC	X		
Utility System Efficiencies, Inc.	LeRoy Patterson	TC			X
Western Area Power Administration (WAPA)	Ken Otto	TC	X		

Voting Summary	Class	Yes	No	Abstain
	SP	1	0	0
	TC	33	2	10
	TP	32	1	1
total		66	3	11

Board of Directors			
April 16-18, 2008		Voting Summary	
Coronado, CA		BAL-002-WECC-1	
Last Name	**First Nar**	**Organization**	**Class**
Anderson	Bob	Non-affiliated Director	Non-Affiliated
Areghini	David	Salt River Project	Class 1
Barbash	Carolyn	Sierra Pacific Power Company	Class 1
Beyer	Lee	California Public Utilities Commission	Class 5
Brown	Duncan	Calpine Corporation	Class 3
Campbell	Ric	Utah Public Service Commission	Class 5
Cauchois	Scott	CADRA	Class 4
Chamberlain	Bill	California Energy Commission	Class 5
Cleary	Anne	Mirant Americas, Inc.	Class 3
Conway	Teresa	Powerex Corp.	Class 6
Coughlin	John	Non-affiliated Board Member	Non-Affiliated
Dearing	Bill	Grant County PUD	Class 2
Ferreira	Richard	TANC Executive Advisor	Class 2
Grantham-Richards	Maude	Farmington Electric Utility System	Class 2
Gutting	Scott	Energy Strategies, LLC	Class 4
Kelly	Nancy	Utah Committee of Consumer Services	Class 4
King	Jack	Non-affiliated Board Member	Non-Affiliated
LaFond	Steve	The Boeing Company	Class 4
*Little	Doug	British Columbia Transmission Corporation	Class 6
McMaster	Dale	Alberta Electrical System Operator	Class 6
Moya	Jesus	Comision Federal de Electricidad	Mexico
Newton	Tim	Non-affiliated Director	Non-Affiliated
Sharpless	Jananne	Non Affiliated Board Member	Non-Affiliated
Smith	Marsha	Idaho Public Utilities Commission	Class 5
Stout	John	Mariner Consulting	Class 3
Tarplee	Gary	Southern California Edison	Class 1
Thuston	Tim	Williams Power	Class 3
Weis	Larry	Turlock Irrigation District	Class 2
VanZandt	Vicki	Bonneville Power Administration	Class 1
Zaozirny	Lori Ann	British Columbia Utilities Commission	Class 6
The Board Members listed above voted whether to approve BAL-002-WECC-1.			
Twenty-eight members voted Yes.			
One member (identified with an asterisk) voted No.			
Two members (not identified) abstained.			

BAL-002-WECC-1 — Contingency Reserves

Action: BAL-002-WECC-1 — Contingency Reserves — **Remand**

Summary Conclusion and Recommendation:

- BAL-002-WECC-1 — Contingency Reserves contains requirements more stringent than NERC's continent-wide standard and cover matters not covered by NERC's Reliability Standards, thereby justifying its consideration as a Regional Reliability Standard.
- Several commenters offered challenges to the technical basis for the change in contingency reserve assignments and allocations. These challenges serve to rebut the presumption of validity for WECC as a Regional Entity organized on an interconnection-wide basis. On this basis, NERC staff recommends the proposed Regional Reliability Standard be remanded to establish a more sufficient technical justification for the change in R1.1.2.
- Until NERC's definition of Spinning Reserve is revised to allow for the use of resources other than generation, propose a modification to the standard that permits the use of demand side resources in all facets of contingency reserve, including spinning reserve, provided the demand side resources meet requirements comparable to generation resources used for the same purpose, consistent with FERC Order No. 693.
- Consider incorporating other suggestions for improving the standard offered in NERC's evaluation.

Background: WECC-BAL-STD-002-0 — Operating Reserves establishes specific operating reserve requirements for Balancing Authorities or Reserve Sharing Groups in the Western Interconnection that are more stringent and include areas not covered in NERC's continent-wide standards, thereby satisfying the statutory criteria for approval as a Regional Reliability Standard. WECC explained the standard is more stringent because the continent-wide NERC Reliability Standard, BAL-002-0 — Disturbance Control Performance requires contingency reserves to be restored within 90 minutes following a disturbance while WECC requires restoration within 60 minutes per its standard. In addition, WECC explained the standard covers areas not covered in the continent-wide NERC Reliability Standard by requiring each Balancing Authority in the Western Interconnection to provide a minimum reserve of five percent of the loads served by hydro generation and seven percent of the loads served by thermal generation.

In its June 8, 2007 Order approving eight WECC Regional Reliability Standards that included WECC-BAL-STD-002-0, FERC directed WECC to make conforming changes to the standard based on the shortcomings identified in NERC's evaluation of the standard, as follows:

1. Remove the sanctions table that is inconsistent with the NERC Sanction Guidelines and add Violation Risk Factors and Violation Severity Levels;
2. Address the inconsistencies with three Regional definitions that conflict with existing terms in the NERC Glossary of Terms:
    a. Automatic Generation Control,
    b. Disturbance Frequency Bias, and

c. Non-Spinning Reserve;

3. Conform the standard to the form of NERC Reliability Standards with respect to the effective date, stating it should become effective on the first day of following quarter upon regulatory approval; and,
4. Attach references made in the standard to the standard.

Further, FERC supported NERC's conditions for approval that WECC meet its commitment to address the shortcomings over the course of the year.

Proposed BAL-002-WECC-1 — Contingency Reserves: The proposed Regional Reliability Standard, BAL-002-WECC-1, was submitted to NERC on June 11, 2008 for approval, replacing the FERC approved WECC- BAL-STD-002-0. In processing the proposed Regional Reliability Standard, WECC indicated it utilized its standards development procedure that existed at the time in accordance with its Regional Delegation Agreement with NERC.

The proposed replacement standard, BAL-002-WECC-1, was modified such that it no longer contains the sanctions table; includes Violation Severity Levels, Violation Risk Factors, Measures and Time Horizons; conforms the effective date format to that of the NERC Reliability Standards; conforms the overall format of the standard to that of the NERC Reliability Standards; eliminates the proposed terms that conflicted with the NERC Glossary of Terms; and attached the references in the standard to the standard itself. WECC also modified the standard numbering to conform to the NERC standards numbering convention.

In addition to making the conforming changes noted above, WECC significantly modified the original FERC-approved version of the standard. These modifications included, importantly:

- increasing the restoration time of contingency reserves following a disturbance from 60 minutes to 90 minutes, consistent with the restoration time specified in the continent-wide NERC Reliability Standard, to align with the restoration of contingency reserves with WECC's electronic tagging system approval cycle;
- altering the method of determining the appropriate mix and amount of contingency reserves by requiring a Balancing Authority to carry three percent of its total load and three percent of its total generation as reserves; and,
- specifying that non-spinning reserves must be capable of being activated within ten minutes.

Because of these additional changes, the proposed standard no longer proposes requirements that are more stringent than the continent-wide NERC Reliability Standard regarding the restoration time of contingency reserves. However, the proposed standard continues to cover matters not covered by an existing continent-wide NERC Reliability Standard and Requirement R1.1.2 continues to provide a superior practice of requiring reserves above the most single severe contingency criteria. Therefore, there is sufficient basis to consider the proposed standard as a valid Regional Reliability Standard. Specifically, BAL-002-WECC-1 proposes requirements that specify WECC's contingency reserve policies that implements and adds more depth to R2 of NERC's BAL-002-0 — Disturbance Control Performance standard.

NERC 45-Day Posting: Upon WECC's board action in April 2008, WECC submitted its seven proposed Regional Reliability Standards to NERC for the required 45-day public posting that took place from April 4–May 20, 2008. The proposed Regional Reliability Standards received several comments during the NERC posting that were provided to WECC for response.

Significant technical and procedural comments were received during the NERC posting on BAL-002-WECC-1. Commenters expressed concern that the drafting team did not address all concerns expressed during the WECC comment periods. WECC replied that they did respond to all written comments and asserted that the approved WECC standards development process was used to develop the revised standard. In addition, WECC clarified there was no consensus among the industry on these concerns; however, there was general consensus within the drafting team regarding the language of the standard. WECC further responded that both transmission providers and transmission customers approved the standard in accordance with its process.

Significant concerns were expressed on the change in reserve requirement of the load responsibility from hydro and thermal generation from five and seven percent respectively, to the sum of three percent of total load and total generation. The comments indicated there was not compelling technical justification for the technical change. WECC explained eight hours of the year were analyzed, including dates from each of the four seasons (both on- and off-peak) and the technical justification is that the proposal provides a clear requirement without reducing the amount of reserves required in WECC. Commenters expressed concern that such a small sample size makes it difficult to properly establish risks associated with implementation. WECC added that since they are a separate interconnection there are no reliability risks to other interconnections or Regions.

WECC supplied NERC with its response to comments on June 11, 2008 requesting NERC's approval of its Regional Reliability Standards. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting.

NERC Evaluation: On June 11, 2008 WECC submitted the seven Tier 1 replacement standards for NERC evaluation. In accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*, approved by the Regional Reliability Standards Working Group, NERC provided its evaluation of the proposed BAL-002-WECC-01 standard to WECC on July 30, 2008 (found in Appendix 4 to this report). In this report, NERC expressed several concerns regarding the additional modifications made to the proposed Regional Reliability Standard beyond the FERC and NERC-directed changes:

- NERC's main concern is the proposed standard no longer proposes more stringent requirements than the NERC Reliability Standard in that the restoration time following a disturbance was increased to match the continent-wide NERC standard.
- In addition, the modification in the amount of contingency reserves to the sum of three percent of the total load and total generation from the existing five and seven percent load responsibility served by hydro and thermal generation, respectively, represents a fundamental shift in approach that appears to lack sufficient technical analyses and justification, with potential significant impacts to entities within WECC. As several commenters expressed this concern in the WECC development process and in the NERC 45-day posting without a sufficient technical basis provided by WECC other than the approximate level of reserves is maintained comparable to current levels in the small sample size analyzed, **there is sufficient basis to rebut the WECC presumption of validity** that exists for a Regional Entity organized on an interconnection-wide basis. Undoubtedly, NERC agrees the proposed standard as modified does reduce ambiguities that existed in the

previous version of the standard; however, there is a lack of justification for the specific percentages and allocations chosen that merit further exploration.

- NERC expressed concern that the proposed standard imposes a limitation on the use of demand-side resources by requiring any spinning reserve should immediately and automatically respond proportionally to frequency deviations, e.g., through the action of a governor or other control system, and be capable of fully responding within 10 minutes. WECC clarified that the "interruptibles" category is intended to include demand-side resources such that they can be included per its definition of Contingency Reserve; however, NERC's definition of Spinning Reserve does not permit the use of resources other than generation and WECC conformed its standard to this definition. When NERC's definition of Spinning Reserve is modified to include resources other than generation, WECC is prepared to include demand-side resources in its standard.
- In addition, NERC made suggestions to improve the clarity of the requirements and added a table containing the Violation Severity Levels to conform to the NERC Reliability Standards.

WECC's response to NERC's evaluation is contained in Appendix 5 to this report.

Supporting Documents:

- Appendix 1 — Regional Reliability Standard Submittal Request
- Appendix 2 — Standard Development Roadmap
- Appendix 3 — Consideration of Comments document on NERC's posting of the regional standard
- Appendix 4 — NERC Evaluation of WECC Regional Standards
- Appendix 5 — WECC Response to NERC Evaluation
- Appendix 6 — WECC Response to FERC Comments
- Appendix 7 — WECC Consideration of Comment Reports
- Appendix 8 — WECC Standards Drafting Team
- Appendix 9 — WECC Balloting
- Appendix 10 — White Paper: WECC Standard BAL-002-WECC-1 — Contingency Reserves

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Regional Reliability Standard Submittal Request

Region: Western Electricity Coordinating Council

Regional Standard Number: BAL-002-WECC-1

Regional Standard Title: Contingency Reserves

Date Submitted: June 11, 2008

Regional Contact Name: Steven L. Rueckert

Regional Contact Title: Director of Standards

Regional Contact Telephone Number: (801) 582-0353

Request (check all that apply):

- ☒ Approval of a new standard
- ☐ Revision of an existing standard
- ☒ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

- ☒ Yes April 16, 2008
- ☐ No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:

The purpose of this standard is to create a permanent replacement standard for BAL-STD-002-0. BAL-002-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when BAL-STD-002-0 was approved as a NERC reliability standard. The drafting team implemented in the standard additional refinements to address concerns as explained in the document titled, “WECC Standard BAL-002-WECC-1 Contingency Reserves.” To assist in understanding the refinements made to the standard, the drafting team has developed a document

To page 1 resource links

that compares BAL-002-WECC-1, the permanent replacement standard, with the existing BAL-STD-002-0 (see BAL-002-WECC-1 Comparison).

Concise statement of the justification of the request:

The BAL-002-WECC-1 regional reliability standard is more stringent than the continent-wide reliability standard (Standard BAL-002-1 — Contingency Reserves). The new standard addresses the following areas:

1. Demonstrates WECC's compliance with the requirements of NERC Reliability Standard BAL-002-1 R2 that requires each Regional Reliability Organization, sub-Regional Reliability Organization or Sharing Group Reserve to specify its Contingency Reserve policies.
2. It enhances the ability to meet load due to any type of contingency by carrying Contingency Reserves for both generation and load, because Contingency Reserves may be activated for loss of a transaction due to transmission or generation loss.
3. BAL-002-WECC-1 increases the amount of Contingency Reserve above NERC's Reliability Standard BAL-002-1 R3.1 during hours when the amount of the Contingency Reserve requirement based upon an amount equal to the sum of three percent of the load (generation minus station service minus Net Actual Interchange) and three percent of net generation (generation minus station service) is greater than the Contingency Reserve based upon an amount equal to the most severe single contingency.
4. It eliminates ambiguity in the BAL-STD-002-0 related to transactions by eliminating their impact on the determination of requirements (with the exception of Contingency Reserve-specific Transactions). It eliminates the need for WECC to define products that are bought and sold between marketing entities, which is important because the responsible Balancing Authority is not privy to the specifics surrounding each transaction. Each Balancing Authority or Reserve Sharing Group will clearly understand the requirement without having to monitor each transaction and determine the impact of each tag to its reserve requirements.

Other — please attach or include as separate files:

- The text of the regional reliability standard in MS Word format that:
  - has either been, or is anticipated to be, approved by the regional entity's board, and
  - is in a format consistent with the NERC template for reliability standards.
- An implementation plan.
- The regional entity standard drafting team roster.
- The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.
- The final ballot results, including a list of significant minority issues that were not resolved, and
- For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

Completed Actions	Completion Date
1. Post Draft Standard for initial industry comments	September 14, 2007
2. Drafting Team to review and respond to initial industry comments	November 20, 2007
3. Post second Draft Standard for industry comments	November 20, 2007
4. Drafting Team to review and respond to industry comments	January 25, 2008
5. Post Draft Standard for Operating Committee approval	January 25, 2008
6. Operating Committee approved proposed standard	March 6, 2008
7. Post Draft Standard for WECC Board approval	March 12, 2008
8. Post Draft Standard for NERC comment period	April 14, 2008
9. WECC Board approved proposed standard	April 16, 2008
10. NERC comment period ended	May 20, 2008
11. Drafting Team completes review and consideration of NERC industry comments	May 30, 2008

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for BAL-STD-002-0. BAL-002-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when BAL-STD-002-0 was approved as a NERC reliability standard. The drafting team implemented in the standard additional refinements to address concerns as explained in the document titled, "WECC Standard BAL-002-WECC-1 Contingency Reserves." To assist in understanding the refinements made to the standard, the drafting team has developed a document that compares BAL-002-WECC-1, the permanent replacement standard, with the existing BAL-STD-002-0 (see BAL-002-WECC-1 Comparison).

This version of the BAL-002-WECC-1 standard is for NERC Board of Trustee ballot. The WECC Board of Directors approved the standard April 16, 2008. WECC Operating Committee approved the standard March 6, 2008. The WECC Board of Directors and Operating Committee request that the NERC Board of Trustees approve the BAL-002-WECC-1 Standard as a permanent replacement standard for BAL-STD-002-0 and that the NERC Board of Trustees submits the standard to FERC for approval and replacement of BAL-STD-002-0.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. NERC Board approval request	June 2008
2. Request FERC approval	June 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

A. Introduction

1. **Title:** **Contingency Reserves**
2. **Number:** BAL-002-WECC-1
3. **Purpose:** Contingency Reserve is required for the reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

4. **Applicability**

    4.1 Balancing Authority

    4.2 Reserve Sharing Group

5. **Effective Date:** On the first day of the next quarter, after receipt of applicable regulatory approval.

B. Requirements

R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain as a minimum Contingency Reserve that is the sum of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R1.1. The greater of the following:

R1.1.1. An amount of reserve equal to the loss of the most severe single contingency; or

R1.1.2. An amount of reserve equal to the sum of three percent of the load (generation minus station service minus Net Actual Interchange) and three percent of net generation (generation minus station service).

R1.2. If the Source Balancing Authority designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink Balancing Authority shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s). This type of transaction cannot be designated as Spinning Reserves by the source BA. If the Source Balancing Authority does not designate the Interchange Transaction as part of its Contingency Reserve, the Sink Balancing Authority is not required to carry any additional Contingency Reserves under this Requirement.

R1.3. If the Sink Balancing Authority is designating an Interchange Transaction(s) as part of its Contingency Reserve either Spinning or Non-Spinning, the Source Balancing Authority shall increase its Contingency Reserves equal in amount and type, to the capacity transaction(s) where the Sink Balancing Authority is designating the transaction(s) as a resource to meet its Contingency Reserve requirements. These types of transactions could be designated as either spinning or non-spinning reserves. If designated as Spinning Reserves, all of the requirements of section R2.1 & R2.2 must be met.

R2. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

R2.2. Capable of fully responding within ten minutes.

R3. Each Reserve Sharing Group or Balancing Authority shall use the following acceptable types of reserve which must be fully deployable within 10 minutes of notification to meet R1: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R3.1. Spinning Reserve

R3.2. Interruptible Load;

R3.3. Interchange Transactions designated by the source Balancing Authority as non-spinning contingency reserve;

R3.4. Reserve held by other entities by agreement that is deliverable on Firm Transmission Service;

R3.5. An amount of off-line generation which can be synchronized and generating; or

R3.6. Load, other than Interruptible Load, once the Reliability Coordinator has declared a capacity or energy emergency.

C. Measures

M1. The Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group has documentation that it maintained 100% of required Contingency Reserve levels based upon data integrated over each clock hour except within the first 105 minutes (15 minute Disturbance Recovery Period, plus 90 minute Contingency Reserve Restoration Period) following an event requiring the activation of Contingency Reserves. For each hour Reserve Sharing Group or Balancing Authority shall have and provide upon request their Contingency Reserve Requirement in MW, how the requirement was calculated, and amount of Contingency Reserve available in MW. E-tags and/or contracts shall be provided to document any transactions under R1.2 and R1.3.

M2. The Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group has documentation that it maintained at least 100% of minimum Spinning Contingency Reserve required based upon data averaged over each clock hour except within the first 105 minutes following an event requiring the activation of Contingency Reserves. For each hour, Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall have and provide upon request the Spinning Reserve Requirement in MW and amount of Spinning Reserve available in MW that is automatically responsive to frequency and can be fully deployed in 10 minutes.

M3. The Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group has documentation that it used the acceptable types of reserve for each hour to meet R3.

M3.1 Any Reserve Sharing Group or Balancing Authority utilizing Load other than Interruptible Load shall submit documentation demonstrating that the Reliability Coordinator declared a Capacity and/or Energy Emergency prior to utilizing Load for Contingency Reserves.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

The Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports conducted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

Reserve Sharing Groups and Balancing Authorities shall submit to their Compliance Enforcement Authority a Contingency Reserve verification report on or before the tenth business day following the end of each calendar quarter.

1.2.1 Compliance Monitoring Period: One Clock Hour.

1.2.2 The Performance-reset Period is calendar quarter.

1.3 Data Retention

Reserve Sharing Groups and Balancing Authorities shall keep evidence for Measure M.1 through M3 for three years plus current, or since the last audit, whichever is longer.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 1.4.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Section 1.4.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 1.4.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 1.4.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Section 1.4.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 1.4.2 shall be subject to this Standard on an individual basis.

2. Violation Severity Levels for Requirement R1

2.1. Lower: There shall be a Lower Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve.

2.2. **Moderate:** There shall be a Moderate Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve.

2.3. **High:** There shall be a High Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve.

2.4. **Severe:** There shall be a Severe Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Contingency Reserve is less than 70% of the required Contingency Reserve.

3. Violation Severity Level for Requirement R2

3.1 **Lower:** There shall be a Lower Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Spinning Reserve is less than 100% but greater than or equal to 90% of the required Spinning Reserve.

3.2. **Moderate:** There shall be a Moderate Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Spinning Reserve is less than 90% but greater than or equal to 80% of the required Spinning Reserve.

3.3. **High:** There shall be a High Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Spinning Reserve is less than 80% but greater than or equal to 70% of the required Spinning Reserve.

3.4. **Severe:** There shall be a Severe Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority's or the Reserve Sharing Group's Spinning Reserve is less than 70% of the required Spinning Reserve.

4. Violation Severity Level for Requirement R3

4.1 **Lower:** Not Applicable

4.2. **Moderate:** Not Applicable

4.3. **High:** There shall be a High Level of non-compliance if there is one hour during a calendar month in which the Balancing Authority or Reserve Sharing Group used unacceptable resources for Contingency Reserves.

4.4. **Severe:** Not Applicable

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for BAL-STD-002-0	

Appendix 3

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Report Form for WECC Standard BAL-002-WECC-1 — Contingency Reserves

The BAL-002-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the BAL-002-WECC-1 Standard. This Standard was posted for a 45-day public comment period from April 4, 2008 through May 20, 2008. NERC distributed the notice for this posting on April 7, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were seven sets of comments from forty-two companies representing five of the ten Industry Segments as shown in the table on the following pages.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the Standard can be viewed in their original format at:

http://www.nerc.com/~filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Manager of Regional Standards, Stephanie Monzon at Stephanie.monzon@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is described in the NERC Regional Reliability Standards Development Procedure: ftp://www.nerc.com/pub/sys/all_updl/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Annette Bannon Jon Williamson John Cummings Tom Olson	PPL Generation, LLC PPL EnergyPlus PPL EnergyPlus PPL Montana, LLC					✓	✓				
2.	JJ Jamieson	Portland General Electric Merchant						✓				
3.	Ted Williams	NorthWestern Energy (NWMT)	✓									
4.	Mike Tongue and Angelia (Angie) R. Eide	Puget Sound Energy	✓									
5.	Brad Van Cleve	Industrial Customers of Northwest Utilities Air Liquide Air Products Amcor PET Packaging USA, Inc. Certain Teed Gypsum & Ceiling Manufacturing, Inc. Blue Heron Paper Company Boeing Boise Cascade ConAgra Foods Dyno Nobel, Inc. Eka Chemicals, Inc. Emerald Kalama Chemical, LLC Evanite Fiber Evraz Oregon Steel Mills Georgia-Pacific Grays Harbor Paper, L.P. Hewlett-Packard Inland Empire Paper Co. Intel J.R. Simplot Kimberly-Clark Corporation Longview Fibre Microsoft Corporation Norpac Foods PCC Structural's, Inc.							✓			

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
		Ponderay Newsprint Co. REC Silicon Shell Oil Products US Simpson Paper & Timber SP Newsprint Tesoro Refining and Marketing Co. Wah Chang West Linn Paper Company Weyerhaeuser										
6.	Mike Goodenough	Powerex						✓				
7.	Denise Koehn	Bonneville Power Administration	✓		✓		✓	✓				

Index to Questions, Comments, and Responses

1. **Was the WECC Standard BAL-002-WECC-1 - Contingency Reserves developed in a fair and open process, using the Process for Developing and Approving WECC Standards?**

Summary Consideration:

Commenter	Yes	No	Comment
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
JJ Jamieson		X	The propsed standard was vetted publically on a number of occassions but the drafting team did not respond to all comments posted on the WECC website. A number of key concerns voiced by affected parties were not addressed.
Response: The drafting team responded to all written comments, pursuant to the Process for Developing and Approving WECC Standards approved by FERC as part of WECC's Delegation Agreement with NERC. Comments submitted to the Operating Committee were considered and discussed during open meetings and at the WECC Operating Committee meeting on March 6, 2008, before the vote approving the current language of BAL-002-WECC-1. There was not unanimous agreement regarding what were "key concerns" across the industry; however, there was general consensus regarding the language of the standard within the drafting team and the majority of both transmission providers and transmission customers approved the standard.			
Ted Williams	X		
Response: Thank you.			
Mike Tongue and Angelia (Angie) R. Eide	X		
Response: Thank you.			
Brad Van Cleve		X	The proposed standard was not developed with the input of end use customers. Neither the Industrial Customers of Northwest Utilities ("ICNU") nor its members companies participated in the standard development process. ICNU is an incorporated, non-profit association of large industrial electric customers in the Pacific Northwest. ICNU represents the interests of large end-use consumers. Some of ICNU's members purchase transmission services pursuant to direct access programs, while others pay for transmission costs as part of traditional bundled service. A list of ICNU's member companies is attached to these comments. BAL-002-WECC-1 will likely result in higher costs for ICNU's members. As a result, WECC should have pursued a more thorough process before adopting BAL-002-WECC-1.
Response: Efforts to develop BAL-002-WECC-1 have been underway for over a year following FERC's June 8, 2007 Order approving WECC's Tier One Standards. The BAL-002-WECC-1 standard was developed using the Process for Developing and Approving WECC Standards, which was vetted and accepted by FERC. This process is an open process that permits all industry stakeholders, including end use customers, to participate in the development of			

Commenter	Yes	No	Comment
standards and to comment on each standard. Several ICNU members are also members of WECC and should have been aware of the process through various WECC communications. The WECC process requires public notices of the intent to draft the standard, which included posting on the NERC and WECC websites. ICNU's failure to participate in the process does not mean that that the process was not fair and open.			
Mike Goodenough			
Response:			
Denise Koehn	X		
Response: Thank you.			
Response:			

2. **Does the WECC Standard BAL-002-WECC-1 - Contingency Reserves pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Commenter	Yes	No	Comment
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
JJ Jamieson	X		Only eight hours of data was analyzed during the drafting of the proposed standard making it difficult to properly establish any risks associated with its implementation.
Response: The drafting team analyzed data from the four seasons both on and off peak. The chosen hours were representative of conditions during each season. The drafting team's analysis indentified no reliability risks. The drafting team determined that additional analysis was not necessary due to the selection of hours. Additionally, since WECC is a separate interconnection, there is no reliability risks to other interconnections or regions.			
Ted Williams	X		The reserve requirement specified in this standard (3% of load and 3% of generation) has no technical basis, nor tried-and-true operational experience. To approve this standard without addressing either of these critical items may result in unintentional and unexpected negative reliability consequences. With the removal of reserve-carrying responsibility from E-Tags, as described below, reliability is placed at further risk because Balancing Authorities will not have any verification of who is carrying reserves, or where reserves are being carried, for transactions.
Response: Contingency reserves are needed to ensure loads are served after the unexpected loss of any resource including transmission, generation or			

Commenter	Yes	No	Comment
import schedules. While generators may be lost more often than import schedules or transmission, this does not mean that loss of transmission and import schedules resources should be ignored. Consequently, the drafting team recommended a reserve requirement based on a combination of generation and load. The standard clarifies the contingency reserve requirement in the Western Interconnection, without signifcantly changing the overall interconnection-wide reserve requirements. Under the proposed standard, a Balancing Authority (BA)/Reserve Sharing Group (RSG) can easily calculate its reserve requirement and is not dependent on the type of transaction or the source of a transaction. Therefore, the proposed standard is simpler and clearer in identifying the reserve requirement.			
Mike Tongue and Angelia (Angie) R. Eide		X	
Response: Thank you.			
Brad Van Cleve			
Response:			
Mike Goodenough			
Response:			
Denise Koehn		X	
Response: Thank you.			
Response:			

3. **Does the WECC Standard BAL-002-WECC-1 - Contingency Reserves pose a serious and substantial threat to public health, safety, welfare, or national security?**

Summary Consideration:

Commenter	Yes	No	Comment
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson		X	
Response: Thank you.			
JJ Jamieson		X	Only eight hours of data was analyzed during the drafting of the proposed standard making it difficult to properly establish any risks associated with its implementation.
Response: The drafting team analyzed data from the four seasons both on and off peak. The chosen hours were representative of conditions during each season. The drafting team's analysis indified no reliability risks. The drafting team determined that additional analysis was not necessary due to the selection of hours. Additionally, since WECC is a separate interconnection, there is no reliability risks to other interconnections or regions.			
Ted Williams		X	

Commenter	Yes	No	Comment
Response: Thank you.			
Mike Tongue and Angelia (Angie) R. Eide		X	
Response: Thank you.			
Brad Van Cleve			
Response:			
Mike Goodenough			
Response:			
Denise Koehn		X	
Response: Thank you.			
Response:			

4. Does the WECC Standard BAL-002-WECC-1 - Contingency Reserves pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

Summary Consideration:

Commenter	Yes	No	Comment
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson	X		EPLUW believes that there is an inconsistency between the proposed reliability requirement and the method in which reserves are procured and provided under the existing Open Access Transmission Tariffs (OATT). Transmission Providers (TP) must generally offer operating reserves under their OATTs to Transmission Customers serving load in the TP's Control Area. Otherwise, there is no default supplier of reserves. Further, the implementation of the proposed standard has not been fully explained, and it is unclear if reserves will be available to all market participants that may be required to procure or provide them in the future. EPLUW would like to see these issues addressed before the standard becomes effective.
Response: The proposed standard requires a level of reserves for a BA or RSG. The standard does not address the issue of procuring reserves from other Balancing Areas. The proposed standard merely clarifies reserve responsibility if an interchange schedule is designated by either a sink or source BA as being used to meet its reserve requirement. This has no impact on the availability of reserves for purchase. Delaying the implementation of this standard would not provide the needed clarification in reserve requriements to promote reliability.			

Commenter	Yes	No	Comment
JJ Jamieson	X		The proposed standard will create substantial cost shifting within the interconnection. A competitive market for the supply of reserves within the interconnection has not been established potentially resulting in participants being unable to comply with BAL-002-WECC-1. The physical market liquidity has already been hampered due to shifting of reserve responsiblity.
Response: The proposed standard removes the existing ambiguity that has caused market and reliability uncertainty. This standard does not assume the existence of any market. Rather, it puts a clear requirement on the BAs and RSGs in the Western Interconnection. Source and Sink BAs and RSGs must identify interchange schedules that will be used to meet their reserve requirement, thereby creating certainty. The data analysis during the development of this standard showed only small decreases in the amount of reserves required by the entities responsible for reserves in the Western Interconnection. The drafting team recognized that an RSG may choose to change its allocation methodology, which may cause an increase in an individual member's reserve requirement. The standard, however, does not require an RSG to allocate reserves in any specific manner. An efficient reserves market might help entities reduce their costs, but cost allocation is not the purpose of the standard. The BAL-002-WECC-1 standard does not have an effect on the need for a reserve market. The standard was developed to ensure reliable service to the loads in the Western Interconnection. Development of a reserves market will provide an economically efficient process for maintaining that reliability. This standard does not impede the development of that market. Additionally, it is possible to enter into transactions for non-standard products, so the lack of a standardized product does not prohibit transactions under specific contracts for the desired product.			
Ted Williams	X		With the standard as written, market participants will no longer be concerned about carrying reserves -- in fact, the WECC Interchange Scheduling and Accounting Subcommittee has already voted to remove the WECC Reserve Responsibility field from E-Tags. The result will be that merchants will be selling the maximum output of their generators, and already slim reserves markets will literally disappear. For Balancing Authorities that will likely end up dependent on reserves markets to meet the standard, the outcome created by this standard will be detrimental to both reliability and competitive markets. Additionally, the standard creates an unacceptable shift in risk and cost burden.
Response: The standard creates a clear reserve requirement for RSGs and BAs. It clearly identifies the level of reserves required and the entity responsible for accessing them. The clarification is not a significant deviation from the current requirements and should not impact the competitive market other than to clarify the calculation of a reserve requirement.			

Commenter	Yes	No	Comment
Mike Tongue and Angelia (Angie) R. Eide	X		(4a) Proposed standard, BAL-002-WECC-1, is purportedly designed to implement the directives of FERC and recommendations of NERC when BAL-STD-002-0 was approved as a NERC reliability standard. But the proposed standard is not the result of any technical or operational deficiency in the requirements of BAL-002-WECC-0. The Federal Energy Regulatory Commission (FERC) determined that BAL-002-WECC-0 as a "regional Reliability Standard is sound, as it provides greater stringency than NERC's reserve requirements and meets a need of the Western Interconnection." (Docket No. RR07-11, Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, ¶ 56). The FERC approved BAL-002-WECC-0. The FERC further directed WECC to address shortcomings of the standard identified by NERC and which NERC reported to WECC on January 9, 2007. Identified in the report and of primary concern to the FERC and NERC was the inclusion in the standard of sanction tables which conflicted with NERC's FERC-approved Sanction Guidelines. In addition, NERC identified other administrative shortcomings, including issues relating to proper definition of terms and template formatting and certain ambiguities identified by the commenters. The reliability goal and technical implementation of BAL-002-WECC-0 were not identified as shortcomings and requiring of modification. Therefore, proposed standard, BAL-002-WECC-1, goes well beyond these directions and recommendations to unnecessarily modify the reliability goal in a manner that unduly burdens markets within the Western Interconnection. (4b) In using expedited procedures to develop WECC's initial eight regional Reliability Standards, WECC's rules require WECC to develop permanent, replacement standards using more extensive procedures. Through this process WECC has attempted to clarify ambiguities related to the Contingency Reserve requirements, such as the definition of Load Responsibility, inclusion of market transactions in the determination of reserve requirements and the emergence of market products that do not fit into the reliability concept. While PSE supports efforts to clarify ambiguities, PSE is concerned that a sampling of only 0.0913% of hours out of the year is not adequate support to justify modification to the manner in which reserves are allocated. PSE is concerned that modification to the manner in which reserves are allocated will not achieve any resolution of ambiguities within the standard, but instead will pose a serious and substantial burden on competitive markets within the interconnection

Commenter	Yes	No	Comment
			that is not necessary for reliability. (4c) As described further below, the proposed standard poses a serious and substantial burden on competitive markets within the Western Interconnection in that it unnecessarily and dramatically shifts risk and costs without reasonable justification. The proposed standard would lead to a major cost shift in several areas in the west, i.e., net importing Balancing Authority (BA) areas. Under the proposed standard, the importing BA areas would be required to carry 3% reserves on load, shifting costs from those entities which pose a greater risk or impact to the electric system (generators) to those who do not. Moreover, undeveloped reserve markets in WECC further limit the ability of net importing BA areas to meet their reserve needs. (4d) The proposed standard is unduly burdensome on the market in that it requires that reserves be separated from energy. Under the current standard, buyers in the market can purchase and receive a bundled product wherein the source BA carries extra reserves to maintain the transaction in the event of a loss of generation in the source BA. Under the proposed standard, buyers can no longer purchase this bundled product and must instead arrange a second transaction for reserves and additional firm transmission for those reserves. Furthermore, there currently is not a robust, established reserves market. PSE is concerned that if the appropriate commercial documents etc. are not in place at the time of implementation of this new standard that net importers will suffer as a result. PSE would like to suggest that at the very least, if approved at the NERC and FERC levels, that implementation of the proposed standard be phased-in or an interim adoption period created to provide the market with adequate time to establish the necessary commercial contracts, i.e. to create a liquid reserves market. (4e) The proposed standard further impacts the market in that BAs who are net importers would be required to maintain reserves with out-of-market generation. Contingency reserves are an insurance policy protecting against the potential loss of generation. As loss of generation within the Balancing Authority is the risk, the standard should allow BAs that are net importers to manage the risks (and attendant reserves) within the market in order to minimize the impacts of a loss of generation event on transmission.

Commenter	Yes	No	Comment
			(4f) In conclusion, PSE strongly supports the efforts of WECC to create and implement a permanent solution to contingency reserves and applauds the current work on a Frequency Responsive Reserves (FRR) standard. However, PSE feels that a temporary fix, as provided for in the proposed standard, BAL-002-WECC-1, with wide-ranging market and operational impacts is not beneficial to the region. A WECC-approved FRR process in combination with the Most Single Severe Contingency is the most technically defensible and appropriate solution for providing for contingency reserves in the Western Interconnection. It is PSE's hope that the complex implementation of the proposed standard does not distract from or delay more important work on an FRR process.

Response: (4a) The drafting team developed the standard through an open process in which it endeavored to address the issues raised in the process of implementing the emergency standards. In addressing the concerns raised related to definition of terms, the drafting team determined that it would not be able to define the term "Load Responsbility" without defining market products. This would be outside of the scope of WECC and potentially an issue of limiting the market in an unjust and unreasonable manner. Therefore, the drafting team recommended a standard that would result in a small change to the overall reserve requirement in WECC, but would produce a clear reserve requirement for Balancing Authorities and RSGs. The difficulty associated with the technical implementation of the current standard is a significantreliability shortcoming. Without a clear definition of load responsibility, there is no way to implement the current reserve requirement. The primary reliability goal is to ensure that Balancing Authorities and Reserve Sharing Groups have sufficient reserves to provide reliable service to the loads in the Western Interconnection. The new language accomplishes that while leaving room for markets to develop to meet those reserve requirements.

(4b) These issues were considered by both the drafting team and the balloting groups in WECC. The resolution of the ambiguities is a result of clearly defining the reserve requirement, which is very near that of the existing standard, and the methodology for calculating those reserves. The drafting team analyzed data from the four seasons, both on and off peak. The hours used were representative of conditions during each season. No one has offered any evidence that these hours were not representative of the majority of the hours in a year or that these hours were not representative of the critical hours of a year. As for the burden on the markets, it is the position of market participants that were part of the drafting team that this will greatly alleviate issues that have been seen in the market since the implementation of the tools necessary to track the current standard. This is further evidenced by the WSPP documents that have been developed both prior to and since WECC approved the proposed standard.

(4c) The proposed standard removes the existing ambiguity that has caused market and reliability uncertainty. This standard does not assume the existence of any market. Rather, it puts a clear requirement on the BAs and RSGs in the Western Interconnection. Source and Sink BAs and RSGs must identify interchange schedules that will be used to meet their reserve requirement, thereby creating certainty. The data analysis during the development of this standard showed only small decreases in the amount of reserves required by the entities responsible for reserves in the Western Interconnection. The drafting team recognized that an RSG may choose to change its allocation methodology, which may cause an increase in an individual member's reserve requirement, The standard, however, does not require an RSG to allocate reserves in any specific manner. An efficient reserves market might help entities reduce their costs, but cost allocation is not the purpose of the standard. The BAL-002-WECC-1 standard does not have an effect on the need for a reserve market. The standard was developed to ensure reliable service to the loads in the Western Interconnection. Development of a reserves market will provide an economically efficient process for maintaining that reliability. This standard does not impede the development of that market. Additionally, it is possible to enter into transactions for non-standard products, so the lack of a standardized product does not prohibit transactions under specific contracts for the desired product.

Commenter	Yes	No	Comment
(4d) The current standard does not allow an entity to buy a bundled product of both reserves and energy. The current standard allows an entity to buy energy and reduce its reserves requirement if the seller takes load responsibility and, thus, agrees to provide reserves. This, however, creates the same requirement that reserves be available for purchase from the source BA. Consequently, the buyer of that energy did not purchased reserves, it was only permitted to reduce its reserve requirement based on the seller's agreement to take load responsibility. While some claim that there is the ability to have the reserves delivered based on the type of transaction, that assertion has not been supported and has led to some confusion in the market. In an RSG, the RSG determines the allocation and delivery within the reserve sharing group. In certain cases when both the buyer and seller are in the same RSG, that group's rules allow for delivery of reserves over transmission lines, but that delivery is based on allocation rules, not the transaction itself. Additionally, the argument that the lack of a robust market should forestall the implementation of this standard is misplaced. The current rules were written long before there was a robust market for any energy products. As the markets have evolved, the current rules have limited some parties ability to participate. The propsoed standard removes these barriers to entry and will allow all parties to participate on a reasonably level playing field through clear rules on which market products can be developed. (4e) Contingency reserves are needed to ensure loads are served after the unexpected loss of any resource including transmission, generation or import schedules. This is consistent with the current standard and the pro forma Open Access Transmission Tariff. While generators may be lost more often than import schedules or transmission, this does not mean that the later two resources should be ignored. (4f) The approval of BAL-002-WECC-1 does not impeed or prevent the development of a Frequency Response Reserve Standard. The comment includes several assumptions about a possible standard that has not been determined through a technically defensible process, nor has the WECC membership agreed to methodologies needed to implement such a standard. Those fully involved in development of a standard do not at this time agree on basic issues such as the level of Frequency Responsive Reserve needed, the means of measuring response, and the amount of interaction between contingency reserves. Due to the limited time permitted to develop a permanent replacement standard for BAL-STD-002-0, coordination between the two processes was not possible.			
Brad Van Cleve	X		The proposed standard requires a minimum for Contingency Reserves equal to the sum of three percent of load and three percent of net generation. This is a change from the current standard, which places the responsibility upon generation, with a reserve requirement of five percent for hydro generation and seven percent for thermal generation. There is no evidence that the shift of part of the responsibility for Contingency Reserves from generation to loads will have any positive impacts upon reliability. The change appears to have been made based on a "compromise" by WECC, and not based on operational or reliability needs. The proposed standard will likely impose a serious and substantial burden on competitive electricity markets in the Pacific Northwest that is not necessary for reliability. Shifting part of the responsibility for Contingency Reserves from generation to loads will result in significant cost shifts within the Pacific Northwest markets, without any demonstration of any reliability benefits. For example, Puget Sound Energy

Commenter	Yes	No	Comment
			("PSE") has estimated that its retail customers could pay an additional $14 million more per year for increased Contingency Reserve obligations. The WECC drafting team agreed that PSE's estimate of additional costs is a possible outcome. The proposed standard also may have harmful impacts on the direct access programs in the Pacific Northwest. Shifting responsibility for Contingency Reserves from generators to loads could cause unintended, harmful impacts upon the existing wholesale power markets and upset current contractual arrangements. The proposed standard also may harm hydro dependent utilities in the Pacific Northwest. The current standard recognizes the lower Contingency Reserve needs for hydro generation. The new standard, without any factual support, increases the Contingency Reserve requirements for utilities with large hydro systems. In the absence of a clear reliability benefit, the current standard for Contingency Reserves should not be changed, especially since the change will cause cost shifts and unintended market consequences. If such a change does occur, it should come only after these impacts have been studied and mitigated.

Response: Contingency reserves are needed to ensure loads are served after the unexpected loss of any resource including transmission, generation or import schedules. The standard creates a clear reserve requirement for RSGs and BAs and clearly identifies the level of reserves required. The standard requires that reserves are deployable when activation is required. All these requirements enhance reliability in the Western Interconnection.

The proposed standard removes the existing ambiguity that has caused market and reliability uncertainty. This standard does not assume the existence of any market. Rather, it puts a clear requirement on the BAs and RSGs in the Western Interconnection. Source and Sink BAs and RSGs must identify interchange schedules that will be used to meet their reserve requirement, thereby creating certainty. The data analysis during the development of this standard showed only small decreases in the amount of reserves required by the entities responsible for reserves in the Western Interconnection. The drafting team recognized that an RSG may choose to change its allocation methodology, which may cause an increase in an individual member's reserve requirement, The standard, however, does not require an RSG to allocate reserves in any specific manner. An efficient reserves market might help entities reduce their costs, but cost allocation is not the purpose of the standard. The BAL-002-WECC-1 standard does not have an effect on the need for a reserve market. The standard was developed to ensure reliable service to the loads in the Western Interconnection. Development of a reserves market will provide an economically efficient process for maintaining that reliability. This standard does not impede the development of that market. Additionally, it is possible to enter into transactions for non-standard products, so the lack of a standardized product does not prohibit transactions under specific contracts for the desired product.

The proposed standard removes the existing market ambiguity that has caused market and reliability uncertainty. This standard does not assume the existence of any market. Rather it puts a clear requirement on the BAs and RSGs in the Western Interconnection. All data evaluated during the development of this standard show only small decreases in the amount of reserves required by the entities responsible for reserves in the Western

Commenter	Yes	No	Comment
Interconnection.			

Commenter	Yes	No	Comment
Mike Goodenough	X		BAL-002 may require most (if not all) jurisdictions to reform their existing tariffs and/or rate schedules to reflect the different way they will have to recover ancillary service costs, as well as potential changes to the obligations for Transmission Providers to sell ancillary services. Based on its comments below, Powerex also believes there may also be issues with third parties ability to self-supply or procure ancillary services from other providers. Such reforms can be lengthy processes, normally requiring various stakeholder consultations, customer information processes, etc. It does not seem likely that these processes could be completed in time for the planned implementation of the standard. Further compounding the problem is the fact that many jurisdictions are completing the tariff reforms required by Order 890. It may be difficult for jurisdictions to adjust their tariff reform process in a sufficiently timely manner to implement the new standard. Market Impacts: One of the fundamental problems with BAL-002 is the fact that it assumes the existence of a liquid ancillary service market: no such market exists in the WECC as a whole. Shifting the operating reserve responsibility away from the source to the load will result in significant increases in the operating reserve requirements of a number of jurisdictions (e.g. those who are primarily load-based) and will therefore require them to procure operating reserves outside their own jurisdictions. Because there has been no technical studies done to evaluate the ability of entities to acquire operating reserves, it is not at all clear if reserve-deficit entities will be able to meet the new requirements. Some of the impediments include: Lack of Firm transmission to facilitate the trade of operating reserves - Operating reserves are required to be carried on firm transmission, and due to constraints in the grid, not all entities are able to purchase firm transmission back to their systems. This problem is expected to get worse as grid continues to become more constrained. Business Practices/Operational Dispatch - In several instances, business practices of the differing providers may not allow for operating reserves to be transmitted across their areas in a manner efficient enough for a fluid market to exist. The dispatch of operating reserves can be largely a manual process for a number of jurisdiction. Though it fully expected that the number of operating reserve transaction will drastically increase with the implementation of BAL-002, the impact those transaction will

Commenter	Yes	No	Comment
			have on the dispatchers and their systems and processes has not been considered. Product Standardization - As stated above, BAL-002 assumes that an operating reserve market will develop to meet the new requirements imposed on the WECC BAs. One of the requirements for a liquid market to exist is product standardization; entities will need to know the characteristics of the product they will be trading in advance, otherwise the market cannot trade in a fluid and efficient manner. As of now, no standard operating reserve product exists. In fact, neither the EEI nor the WSPP agreements have operating reserves defined anywhere as tradable products. Because of the number of characteristics that need to be defined for operating reserves (e.g. ramp rate, number of dispatches per hour, per day, the dispatch priority of the product, etc.) it may be difficult for the market as a whole to a agree on standard products.

Response: All data evaluated during the development of this standard show only small decreases in the amount of reserves required by the entities responsible for reserves in the Western Interconnection. The entities that have claimed a possible increase in their reserve requirements have all been members of Reserve Sharing Groups. The data show that the RSGs in question will all see either no change or a slight decrease in their requirements. An RSG may change its allocation methodology that may cause an increase in an individual member's reserve requirement. This standard recognizes the need for clear reserve calculations in either a predominately load BA or predominantly generation BA. This may result in a cost shift between BAs within an RSG. However, the standard provides clear requirements, rather than assumptions on load responsibility that may not actually be available under current tariff arrangements.

If a provider believes the new reserve requirement has changed its revenue requirement significantly as a result of the potential cost shift, it can file for a change in rates. If a customer believes that the change in requirements changes the provider's revenue requirement significantly, the customer can file a rate proceeding against the provider. The regulatory process does not guarantee either the customer or provider perfect pricing, but does ensure that it is just and reasonable. A fixed percent in a tariff will never exactly match the reserves for an entity. These requirements, however, do not place a serious or substantial burden on the competitive markets within the Western Interconnection. Instead, they promote reliability through clearly defined requirements and there is no reason to delay the implementation of this standard.

As for self-provision or procurement of contingency reserves, this standard does not in any way limit an entity's ability to procure reserves in any manner that meets the clear requirements of the standard. At a very basic level, the standard requires either unloaded generation capacity that can be delivered to the BA/RSG or interruptible loads that can be curtailed within 10 minutes of notification. This in no way limits any entity from self-providing or procuring reserves. The deliverability of these reserves is required to be on firm transmission, which is the same requirement that has been required in WECC for years.

In summary, the possible need to change a tariff to address cost recovery should not hinder making changes to the reserve standard. The fact that some entities may need to adjust rates is not a reason to delay the implementation of this new standard.

Commenter	Yes	No	Comment
Market Impacts: This standard does not assume the existence of any market. Rather it puts a clear requirement on the BAs and RSGs in the Western Interconnection. All data evaluated during the development of this standard show only small decreases in the amount of reserves required by the entities responsible for reserves in the Western Interconnection. The entities that have claimed a possible increase in their reserve requirements have all been members of RSGs. The data show that the RSGs in question will all see either no change or a slight decrease in their requirements. The drafting team recognizes an RSG may change its allocation methodology that may cause an increase in an individual member's reserve requirement. This standard recognizes the need for reserves in a predominately load BA and generation BA. This may result in a cost shift between BAs within an RSG. The standard does not require an RSG to allocate reserves in any specific manner. Lack of Firm transmission to facilitate the trade of operating reserves: The ability to obtain reserves from other entities is not guaranteed, nor required for compliance with this standard. All that is required for compliance is to carry a specified level of reserves. Only if reserves are obtained from another entity is firm transmission required. If an entity carries all of its reserves on its own network resources, no additional transmission is required. Therefore, compliance with this standard does not require any level of firm transmission. Ultimately, the goal of the standard is reliable service to customers, not the facilitation of the trading of operating reserves. Business Practices/Operational Dispatch: The existence of a market is not a requirement of this standard. While it may be economically beneficial to the entities in the Western Interconnection for a market to exist, this is not the goal of the standard. The goal of the standard is to ensure reliable service to the customers in the Western Interconnection. If entities believe that they can provide equivalent service at a lower cost to their customers, this will be an incentive to work to create an efficient market. If business practices prohibit efficient operations, then there will be an incentive to change the business practices to allow for greater efficiencies. To say that a standard cannot be adopted because there might be business practices that will cause issues with efficient operation is putting form ahead of function. The deployment of contingency reserves does not change with the implementation of this standard. Each RSG is a single entity for R3.4. Therefore, R3.4 does not require firm transmission within an RSG. It is the RSG's responsibility to ensure that reserves are deliverable internal to the group. The current practice of Pacific Northwest RSG to monitor available transmission within an operating hour may continue. Product Standardization: An efficient reserves market might help entities reduce their costs, but this is not the purpose of the standard. The BAL-002-WECC-1 standard does not have an effect on the need for a reserve market. The standard was developed to ensure reliable service to the loads in the Western Interconnection without impeding a reasonably efficient energy market. If market participants believe that a standardized product would benefit the entities subject to the requirements of this standard, then this standard may provide the incentive needed to develop the product in the future. It is possible to enter into transactions for non-standard products, so the lack of a standardized product does not prohibit transactions under specific contracts for the desired product. Ultimately, if an efficient market is truly desired, the proposed standard will allow a more efficient market than anything the Western Interconnection has had in the past.			
Denise Koehn		X	
Response: Thank you.			

Commenter	Yes	No	Comment
Response:			

5. Does the WECC Standard BAL-002-WECC-1 - Contingency Reserves meet at least one of the following criteria?

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Commenter	Yes	No	Comment
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			
JJ Jamieson			
Response:			
Ted Williams	X		
Response: Thank you.			
Mike Tongue and Angelia (Angie) R. Eide			
Response:			
Brad Van Cleve			
Response:			
Mike Goodenough			
Response:			
Denise Koehn	X		
Response: Thank you.			

Commenter	Yes	No	Comment
Response:			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Evaluation of Western Electricity Coordinating Council (WECC) Regional Standards

Executive Summary
July 30, 2008

On June 11, 2007, the WECC submitted the following seven regional standards for NERC evaluation to replace eight original WECC regional standards approved by NERC and FERC in 2007:

- BAL-002-WECC-1 — Contingency Reserves,
- FAC-501-WECC-1 — Transmission Maintenance,
- IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief,
- PRC-004-WECC-1— Protection System and Remedial Action Scheme Misoperation,
- TOP-007-WECC-1 — System Operating Limits,
- VAR-002-WECC-1 — Automatic Voltage Regulators and
- VAR-501-WECC-1 — Power System Stabilizer

NERC posted these seven proposed regional standards for a 45-day public posting beginning April 4–May 20, 2008. The standards received several comments during the NERC public posting. WECC supplied NERC with its responses to the comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting. WECC submitted these standards for NERC evaluation on June 11, 2008.

In accordance with NERC's *Rules of Procedure* and the *Regional Reliability Standards Evaluation Procedure* approved by the Regional Reliability Standards Working Group, NERC performed a review of the WECC proposed standards. The intent of this document is to provide WECC with NERC's feedback regarding their regional standards.

In this review, NERC presents a summary of observations for each proposed WECC regional standard. In Appendix A, NERC includes a redlined copy of each proposed regional standard with detailed comments included. NERC believes WECC has satisfied its procedural obligations as outlined in Appendix C of its Regional Delegation Agreement. However, NERC offers concerns and suggestions regarding several of the proposed regional standards that are discussed below.

Summary of Findings

BAL-002-WECC-1 — Contingency Reserves

In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

1. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

2. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

    R4. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

    R4.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

    R4.2. Capable of fully responding within ten minutes.

    In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

3. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

4. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

FAC-501-WECC-1 — Transmission Maintenance

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

1. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

2. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

1. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

2. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

3. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

1. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

2. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

3. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

4. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

TOP-007-WECC-1 — System Operating Limits

1. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

2. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

VAR-002-WECC-1 — Automatic Voltage Regulators

1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

   More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

VAR-501-WECC-1 — Power System Stabilizer

1. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a

justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

Conclusion

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC's Response to NERC's Comments
August 13, 2008
Draft

INTRODUCTION

WECC appreciates NERC staff's evaluation of the proposed WECC Regional Reliability Standards (RRSs) in accordance with NERC's Regional Reliability Standards Evaluation Procedure. These proposed WECC RRSs were developed as permanent replacements for the eight WECC Tier 1 RRSs that previously were approved by NERC and FERC. WECC asserts that the seven proposed standards contain all the performance elements of a Reliability Standard that are contained in the NERC Reliability Standards Development Procedure. In addition, the seven proposed standards address and implement the refinements directed by FERC's order on June 8, 2007 (see FERC Docket No.
RR07-11-000) and requested by NERC in its letter dated January 9, 2007. Finally, these proposed standards implement refinements to the approved WECC Tier 1 RRSs which were recommended during the previous expedited direct translation standard development processes.

The attached WECC responses individually address each NERC comment. However, many of the comments submitted by NERC staff relate to refinements that NERC has made to the format of its Reliability Standard Template. These refinements have not been formally approved by NERC, nor have they been transmitted to the regions for comment or additional information, and were therefore unavailable to WECC during the development process. Consequently, WECC has determined not to reopen the standards development process at this stage to address these non-substantive formatting concerns. In addition, during the standards development process, WECC staff twice requested that NERC staff review the proposed WECC standards. WECC did this to ensure that the WECC standard drafting teams were complying with NERC's Regional Reliability Standards Evaluation Procedure as well as its Reliability Standards Development Procedure. NERC did not perform the evaluation of these proposed standards until WECC had completed its Process for Developing and Approving WECC Standards. WECC intends to implement the requested formatting refinements and any potential FERC-directed changes during the next revision of these standards or the next FERC compliance filing.

The proposed WECC RRSs were considered and adopted pursuant to the Process for Developing and Approving WECC Standards. Unless they are approved in their current form, WECC will have to reinitiate the entire process. The consequences of rejecting these WECC RRSs in their entirety would be counterproductive to reliability in the Western Interconnection.

The proposed WECC RRSs will enhance reliability in the Western Interconnection and they will significantly improve the existing eight WECC RRSs because they:

1. Implement ordered NERC and FERC refinements to the existing standards ordered;
2. Eliminate conflicting NERC and WECC requirements contained in the existing RRSs;
3. Include all the Performance Elements of a Reliability Standard;
4. Clarify existing WECC RRSs;
5. Align better with NERC's Functional Model, and
6. Address industry stakeholder concerns.

Therefore, WECC requests the NERC staff recommend approval of these standards to the NERC Board and FERC.

WECC's responses to NERC's initial evaluation are provided in Attachment 1.

Attachment 1

NERC's Written Comments
July 30, 2008
WECC's Written Responses
August 13, 2008

Summary of Findings

BAL-002-WECC-1 — CONTINGENCY RESERVES

NERC COMMENT:
In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

5. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

WECC RESPONSE:
1. The requirements in the BAL-002-WECC-1 Standard as written are clear. Industry stakeholders did not submit any comments questioning the clarity of the standard, nor did they identify a need for an equation. The drafting team does not believe there is any ambiguity in the requirements.

NERC COMMENT:
6. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

R5. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R5.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

R5.2. Capable of fully responding within ten minutes.

WECC RESPONSE:
2. The drafting team wrote the BAL-002-WECC-1 Standard to permit load, Demand-Side Management (DSM), generation, or another resource technology that qualifies as Spinning Reserve or Contingency Reserve to be used as such. In the case of DSM, the declared amount would be required to respond automatically to frequency deviations and be capable of fully responding in 10

minutes. Loads and DSM are not allowed as Spinning Reserve because it is not permitted by the NERC Spinning Reserve definition. NERC requires that the BAL-002-WECC-1 Standard drafting team use NERC's Spinning Reserve definition. If NERC were to modify its Spinning Reserve definition to allow frequency responsive load tripping as part of a Balancing Authority's DSM, then its use would be permitted under the requirements of the BAL-002-WECC-1 Standard as proposed.

NERC COMMENT (continued):

In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

WECC RESPONSE (continued):

DSM that is deployable within 10 minutes is a subset of Interruptible Load. Interruptible load is defined in requirement R3.2 as an acceptable type of Contingency Reserve. As described previously, if NERC modifies its Spinning Reserve and Interruptible Load definitions, then it would be clear that qualifying DSM is permitted as part of Spinning and Contingency Reserves.

NERC COMMENT:

7. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

WECC RESPONSE:

3. The drafting team wrote a paper titled "WECC Standard BAL-002-WECC-1 Contingency Reserves" that provides an explanation supporting the modification. The paper was included as part of the standards approval package filed on June 11, 2008 with NERC.

NERC COMMENT:

8. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

WECC RESPONSE:

4. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

FAC-501-WECC-1 — TRANSMISSION MAINTENANCE

NERC COMMENT:
It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

3. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

WECC RESPONSE:
1. "Transmission Facilities" is not a NERC-defined term in the NERC "Glossary of Terms Used in Reliability Standards" document, although "Transmission" and "Facility" are. The standard drafting team did not capitalize "transmission facilities" because it believes that the combination of these two defined terms was too limiting. WECC recognizes that this may create confusion and it proposes to address this issue during the next revision of these standards or the next FERC compliance filing.

NERC COMMENT:
4. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:
2. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

IRO-006-WECC-1 — QUALIFIED TRANSFER PATH UNSCHEDULED FLOW (USF) RELIEF

NERC COMMENT:

4. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

WECC RESPONSE:
1. The proposed IRO-006-WECC-1 Standard contains all the key reliability requirements and technical elements from the Unscheduled Flow Mitigation Plan (UFMP) that were included in IRO-STD-006-0. The proposed IRO-006-WECC-1 Standard uses NERC's Functional Model terminology to mitigate unscheduled flow <u>during the next operating hour</u>. It is not necessary to reference the remainder of the UFMP because the remaining items contain procedural requirements explaining "how," not "what." The proposed IRO-006-WECC-1 Standard includes requirements to reduce schedules, which then require adjustments to generation patterns. This prevents potential overloads <u>during the next operating hour</u>. Importantly, the requirements for mitigation of an actual (real-time) overload are contained in TOP-007-WECC-1.

NERC COMMENT:

5. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

WECC RESPONSE:

2. WECC acknowledges the difference between the NERC and WECC definitions for Transfer Distribution Factor (TDF). This is caused by the differences between the Eastern Interconnection Transmission Loading Relief process and the Western Interconnection UFMP. This difference in definitions exists even today between the existing FERC-approved IRO-STD-006-0 Standard and the NERC Glossary. Rejecting the proposed standard will not resolve this difference. WECC will work with NERC to resolve this and intends to make any necessary refinements during the next revision of this standard or the next FERC compliance filing. Despite the difference in the TDF definitions, **the proposed standard corrects a basic difference between the existing FERC-approved IRO-STD-006-0 Standard, which places reliability responsibilities upon the Load Serving Entities (LSEs), and the NERC Functional Model.** LSEs do not have the ability to ensure the implementation of the schedule adjustments required in the existing FERC-approved IRO-STD-006-0 Standard.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

5. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

PRC-004-WECC-1 — PROTECTION SYSTEM AND REMEDIAL ACTION SCHEME MISOPERATION

NERC COMMENT:

5. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

WECC RESPONSE:

1. WECC recognizes that the standard drafting team included explanatory text in the requirement section in an attempt to clarify the requirements. However, the duplication does not adversely

impact the applicability, clarity, or the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

6. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

WECC RESPONSE:

2. WECC recognizes that the standard drafting team included System Operators and System Protection personnel in the requirements. R1. of PRC-004-WECC-1 states that, **"System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection Systems and RAS operations."** As written the requirement is sufficiently clear and well-defined to be enforceable on the entities in the Western Interconnection. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

7. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

WECC RESPONSE:

3. WECC recognizes that the standard drafting team included explanatory text in the requirement section that might be more appropriately included as a footnote. However, the text clarifies the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

8. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

WECC RESPONSE:

4. The requirements in the PRC-004-WECC-1 Standard are clearly written. Industry stakeholders did not submit any comments questioning the clarity of the standard. The alternative standard drafting formats or language used in this standard, are applicable exclusively to the Western Interconnection. These stylistic differences do not affect others and should not be a consideration for NERC approval.

<u>TOP-007-WECC-1 — SYSTEM OPERATING LIMITS (SOLs)</u>

NERC COMMENT:

3. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable

operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

WECC RESPONSE:

1. In the Western Interconnection, SOLs are designed so that during steady-state operations, with all lines in service, the system is at least two contingencies away from cascading. Therefore, exceeding an SOL for the 40 major paths identified in the TOP-007-WECC-1 Standard would not typically qualify as an Interconnection Reliability Operating Limit (IROL) under NERC's TOP-007-0 Standard. The standard drafting team created the TOP-007-WECC-1 Standard to limit the amount of time that a SOL may be exceeded for these very important paths, which makes the TOP-007-WECC-1 Standard more stringent than the NERC standard.

NERC COMMENT:

4. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

WECC RESPONSE:

2. The existing standard created confusion during system operation because system conditions may change the limiting conditions on a path. This is because the limit depends upon whether thermal, stability, or post transient limitations are the limiting factor. In addition, having different response times for paths (and sometimes for the same path depending on current outage conditions), complicates system operation, causing delays in responding to the path overload. This resulted in path operators implementing more drastic actions to respond to a contingency within 20 minutes, which may put the system at greater risk, particularly during heavy load periods such as summer. The standard drafting team determined that changing the standard from a 20-minute to a 30-minute response time is insignificant in terms of the probability of a next contingency occurring. Moreover, the drafting team believes that following a system disturbance, the system operators will be better able to identify what generation to ramp in order to be effective in mitigating the overload. This will also allow them to coordinate with others before implementing the generation ramps. Therefore, the simplification of the standard to one consistent 30-minute period improves reliability. It is important to recognize that in spite of extending the recovery period, the refinement should improve system reliability.

<u>VAR-002-WECC-1 — AUTOMATIC VOLTAGE REGULATORS (AVRs)</u>

NERC COMMENT:

4. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-002-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002a-1 Standard. The 98 percent in Requirement R1. of VAR-002-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002a-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring the AVR to be in service provides for time to start up generating facilities. It also allows for evaluation when the Generator Operators respond to unforeseen events.

NERC COMMENT (continued):
More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

WECC RESPONSE (continued):
NERC VAR-002-1a R1. permits the Generator Operator to operate in different modes by simply notifying the Transmission Operator. There are no restrictions on the length of time or reasons for operating in other modes. The WECC 1996 outage reports identified the lack of reactive support from generators with AVRs operating in modes other than voltage control as one of the causes of the WECC 1996 outages. The VAR-002-WECC-1 Standard limits the reasons and time for operating a generator without the AVR in service and controlling voltage, therefore it is more stringent than the NERC VAR-002-1a Standard.

NERC COMMENT

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the AVR in service). The use of peaking units adds to overall system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

VAR-501-WECC-1 — POWER SYSTEM STABILIZER (PSS)
NERC COMMENT:

4. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-501-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002b-1 Standard. The 98 percent in Requirement R1. of VAR-501-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002b-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring PSS to be in service provides time for evaluation and to start up generating facilities when Generator Operators respond to unforeseen events.

NERC COMMENT:

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the exiting standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the PSS in-service). Operating at low megawatt levels makes the PSS ineffective. The use of peaking units adds to over-all system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture PSS in service recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes that the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

(NERC) CONCLUSION

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC RESPONSE

WECC appreciates the opportunity to discuss NERC staff's initial evaluation and report in conference calls on August 4 and 5, 2008 and to provide the written clarifications and responses contained herein. We trust that WECC's responses, along with all the supporting documentation contained in WECC's submissions, provide the NERC staff a comprehensive basis for recommending NERC Board of Trustees approval of all proposed standards. Please direct any questions relating to WECC's response to WECC Director of Standards, Steve Rueckert at steve@wecc.biz or (801) 883-6878.

WECC Responses to FERC Staff Concerns and Questions
Regarding the Proposed WECC Tier 1 Standards
June 17, 2008

I. Contingency Reserves — BAL-002-WECC-1

A. Period of Contingency Reserve Restoration: Does the proposed standard modify the current standard to provide a longer period of time of 90 minutes rather than 60 minutes?

Yes, the requirement to restore contingency reserves within 60 minutes was eliminated in the proposed standard. The current standard requires the restoration of contingency reserves within the first 60 minutes following an event. By eliminating this requirement in the proposed standard, WECC adopts the NERC default standard that requires the restoration of contingency reserves within 90 minutes from the end of the disturbance recovery period.[2]

The 60 minute restoration period required by the current standard was developed and used under a manual interchange transaction structure among vertically integrated utilities. As the electric utility industry restructured, there has been a substantial increase in the number of market participants and interchange transactions.[3] To accommodate the increase in number of interchange transactions and market participants an electronic tagging system was implemented in the Western Interconnection. The adoption of an electronic tagging system that accommodates multiple market participants and a large number of interchange transactions made the current mid-hour reserve restoration more cumbersome and made the inappropriate rejection of reserve restoration transactions more likely because such transactions are outside the electronic tagging cycle.

Eliminating the 60 minute reserve restoration requirement and adopting the NERC requirements results in more efficient communication among Balancing Authorities (BAs) because it aligns the restoration of contingency reserves with the electronic tagging system approval cycle. Adopting the NERC contingency reserve restoration requirements reduces the potential for reserve transactions being inappropriately rejected resulting in improved communication among BAs resulting in improved reliability.

B. Shedding of Firm Load: Does the proposed standard change the treatment of the shedding of firm load compared to the current standard?

No, both standards allow for the shedding of firm load under limited circumstances. The addition of requirement R3.4 in the proposed standard clarified the process. During capacity and energy emergencies, a BA or Reserve Sharing Group (RSG) may use load as non-spinning reserves; that is BAs and RSGs will not drop load to maintain their non-spinning reserve requirement. Rather they will use load as part of their non-spinning contingency reserves.

[2] See NERC Standard BAL-002-0 Requirement R6 and WECC Standard BAL-STD-002-0 WR1.d.
[3] Balancing Authorities in the Western Interconnection approve between 2,500 and 4,500 interchange transactions per day.

This standard emphasizes the responsibility of serving customer load first while at the same time protecting the reliability of the Western Interconnection. Even during capacity and energy emergencies, BAs and RSGs are required to comply with the spinning reserve requirements.

C. Deliverability of Contingency Reserves: Does the proposed standard require that contingency reserves be deliverable?

Yes, nothing has changed with respect to the deliverability of contingency reserves.

D. Interruptible Imports: In the current standard the sink BA is required to carry an additional amount of contingency reserves equal to the amount of interruptible imports. Does the proposed standard have the same requirement?

Yes, the term interruptible imports was eliminated from the proposed standard. It was replaced with the added requirement R1.2 which requires that "If the Source BA designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink BA shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s)." This is an improvement from the current standard because it eliminates ambiguity in the term interruptible imports.

E. Demand Side Management: Did the drafting team comply with FERC Order 693 to explicitly allow demand-side management (DSM) to be used for reserves?

Yes, DSM that is deployable within 10 minutes is a subset of interruptible load. Interruptible load is defined in requirement R3.2 as an acceptable type of contingency reserve.

II. Qualified Transfer Path Unscheduled Flow Relief- IRO-006-WECC-1

A. Is the proposed standard intended to address an actual (real time) overload situation?

No, a different standard TOP-007-WECC-1 covers actual (real time) overload situations. The proposed IRO-006-WECC-1 standard includes requirements to reduce schedules, which requires adjustments to generation patterns, to prevent potential overloads during the next operating hour.

B. Should the Unscheduled Flow Mitigation Plan (UFMP) be incorporated in the IRO-006-WECC-1 by reference?

No, the key reliability portions from the UFMP are incorporated in the proposed standard. It is not necessary to reference the remainder of the UFMP.

C. Does the WECC UFMP need to be updated?

Yes, WECC has initiated the process of updating its UFMP.

III. System Operating Limits — TOP-007-WECC-1

A. Could the language in TOP-007-WECC-1 allow for the system to be less than two contingencies away from cascading and more specifically one contingency away from cascading?

No, the proposed standard is designed such that path operations must be at least two contingencies away from cascading during steady state operations. In real time operations when System Operating Limits (SOL) are exceeded for periods not to exceed 30 minutes, there may be system conditions that are less than two contingencies away from cascading.

B. Could IRO-005-2 Requirements R3 and R5 be interpreted that the power system is being operated two contingencies away from a cascading outage while WECC TOP-007-WECC-1 requirement R1 results in the power system being operated one contingency away from a cascading outage?

No, IRO-005-2 requirements R3 and R5 are consistent with the requirements in TOP-007-WECC-1. In the Western Interconnection SOLs are developed in such a manner that the system operation is at least two contingencies away from a cascading failure. This is implicit in the identification of the SOL derivation. If, however, there is a flow that exceeds the SOL, Transmission Operators (TOP) and Reliability Coordinators (RC) must take proactive immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the transmission path exceed the SOL for more than 30 minutes, thus protecting the system from potential cascading for a subsequent contingency.

C. Do SOL changes within the hour extend the time for compliance?

No, SOL changes within an operating hour do not extend the time for compliance.

IV. Automatic Voltage Regulators and Power System Stabilizers — VAR-002-WECC-1 and VAR-501-WECC-1

A. How does VAR-002-WECC-1 coordinate with the new NERC Standard VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules?

VAR-002-WECC-1 contains specific, more restrictive, requirements on generator operators regarding the operation of Automatic Voltage Regulators (AVR) that are not contained in the NERC Standard VAR-002-1. The reasons for these more restrictive requirements are to support transfer capabilities in the Western Interconnection and to address the insufficient supply of reactive power identified as a cause of the 1996 system disturbances in the Western Interconnection. The drafting team designed the VAR-002-WECC-1 Standard to limit the reasons for operating AVRs in a mode that does not control voltage and the amount of time permitted for such operations. Generator operators are still required to comply with all the requirements contained in NERC VAR-002-1.

B. Are Power System Stabilizers (PSS) included in either of these standards?

Yes, VAR-501-WECC-1 contains requirements regarding the in-service operation of PSS.

C. Why were the AVR and PSS replacement period extended to two years from 15 months?

The amount of time to replace AVR and PSS was lengthened to accommodate the approval and procurement time frames for AVR and PSS for nuclear power plants, which are two years.

V. Transmission Maintenance — FAC-501-WECC-1

A. Does the FAC-501-WECC-1 standard reduce the number of lines that are subject to this standard to the SOL limiting factors from the lines and facilities associated with the 40 paths thereby reducing the obligation for maintenance?

No, there is no change in the number of lines or facilities subject to the proposed FAC-501-WECC-1 standard.

BAL-002-WECC-1 — CONTINGENCY RESERVE
COMMENTS DUE OCTOBER 30, 2007
NOVEMBER 19, 2007

MIKE RYAN POSTED: 19.10.2007, 13:59

I appreciate the work put into this necessary replacement for BAL-STD-002-0 and offer the following comments:

• At present, the WECC has four requirements for operating reserves that are captured in BAL-STD-002-0 B.WR1.a.(i)(ii)(iii) and (iv).

The replacement draft seems to drop the contents of (i) on regulating reserve and (iv) on interruptible imports, and then labels what remains as "Contingency Reserve" through a title change.

Is this intended to mean that the identical provisions in WECC MORC are still in effect for WECC members, or does the drafting team mean to eliminate these paragraphs from WECC MORC and fall back on NERC Standards?

If it's the latter, this would seem to eliminate the requirement for a "sink" BA to carry additional reserves for interruptible imports. I would not be in favor of this.

Response: The language related to regulating reserve in the WECC Standard BAL-STD-002-1 states that an entity must meet the NERC Standard BAL-001. Therefore, the language in WR1.a.(i) is duplicative to the NERC standard and not needed in the WECC standard. The WECC standard should not be expected to cover all issues and should only cover very specific items that are required in the standard. The drafting team has removed all items that are discussion, explanation or theory. Only clear, concise requirements have been retained in the standard.

The language related to additional reserves for interruptible imports has been removed and replaced with a requirement to carry reserves if the source is counting the energy as part of its reserves. The current requirement to carry 100% of "interruptible transactions" has no basis. When viewed from a logical perspective rather than a nostalgic perspective, the fact that something could happen does not mean that it is likely to happen. Therefore, the drafting team is recommending that the current requirement be changed to more appropriately require reserves for only those clearly defined transactions that are used by the source to meet its reserve requirements and get away from any attempt to define market products.

The comments also raise an issue related to the existing MORC document language. While it has not yet been determined what to do with existing WECC documents, the drafting team believes that any standard will replace comparable language in any existing document. The drafting team will recommend to the ORCWG that the MORC document be revised to remove the existing language related to contingency reserves as well as any other language that duplicates or conflicts with approved standards.

The contents of (ii) on contingency reserves and (iii) on on-demand obligations are implicitly lumped together as "Contingency Reserve" by the title change which doesn't seem helpful to me

• The contingency reserve requirement is contained in (ii).

I really wish that the drafting team had resisted the temptation to mount another campaign for the elimination of the "load responsibility" in contingency reserves. This attempt to revive the ORSTF debate seems particularly ill-timed as we move to implement a clarified definition for "load responsibility" that was just approved by the WECC's BOD.

Response: The drafting team respectfully disagrees with this position. The drafting team feels that the proposed standard is an improvement over the clarification of the term "load responsibility," especially since there are still some people who disagree with the clarification. Ultimately, a Balancing Authority must balance its loads and resources in order to meet its obligations. It is the drafting team's belief that this proposal will ensure that a Balancing Authority can do so using the proposed standard while not putting them at risk of differing interpretations. This methodology ultimately allocates the contingency reserve amount to entities in the WECC. It does not dictate how or when these reserves can be utilized. Requirement R1.3 is used to identify the needed reserves that is currently termed "on-demand obligations." The drafting team has attempted to clarify this section of the proposed standard.

• The replacement draft drops the language in BAL-STD-002-0 A.4 that try to describe how this standard applies to Reserve Sharing Groups (RSG's) and their members. The members of the NWPP believe that the replacement draft needs to contain similar language, and should also address responsibilities for fines/sanctions allocated by RSG's to their members. What follows is some language drafted by people smarter than me:

o 4. Applicability

4.1 Balancing Authority. This Standard shall apply to a Balancing Authority individually unless the Balancing Authority is a member of a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2.

4.2 Reserve Sharing Group.

4.2.1 This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

4.2.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

4.2.3 If an agent properly designated in accordance with Section 4.2.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 4.2.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 4.2.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

4.2.4 If an agent properly designated in accordance with Section 4.2.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 4.2.2 shall be subject to this Standard on an individual basis

Response: The drafting team has inserted the proposed language in D.1.4 to address the issue raised. The drafting team is unsure if the language proposed will be acceptable to NERC and FERC for inclusion in a Regional Reliability Standard. It is possible that the issue will be resolved in a forum other than a reliability standard. In the event this issue is resolved in another form, the language of D.1.4 will be removed. The drafting team has been assured that the WECC Board will attempt to address this issue at its December meeting through adoption of a policy statement related to this issue.

• The replacement draft replaces the 60 minute limit on the use of operating reserves following their activation with a 105 minute limit. While I support the idea of lengthening the time limit, I note that the NERC limit in BAL-002-0 is set at 90 minutes. Longer time limits are allowed, but require justification. It seems to me that adopting the NERC 90 minute limit makes the most sense.

Response: The NERC limit is 90 minutes following the Disturbance Recovery Period, which is 15 minutes. This gives a total time period from the time of the event to the time of restoration of reserves of 105 minutes. The drafting team modified the language to clarify that the restoration period is the same as NERC's time period.

Thank you for considering my comments.
Michael Ryan
Portland General Electric

Gordon Rawling Posted: 22.10.2007, 15:31

BCTC in support of the NWPP recommends adding the following comments to Section (A) of the proposed Standard BAL-002-WECC-1.

4. Applicability

4.1 Balancing Authority. This Standard shall apply to a Balancing Authority individually unless the

Balancing Authority is a member of a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2.

4.2 Reserve Sharing Group.

4.2.1 This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

4.2.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

4.2.3 If an agent properly designated by a Reserve Sharing Group in accordance with Section 4.2.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 4.2.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 4.2.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

4.2.4 If an agent properly designated by a Reserve Sharing Group in accordance with Section 4.2.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

4.2.5 Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 4.2.2 shall be subject to this Standard on an individual basis.

Response: Please refer to the response to Mike Ryan's comments above.

DON BADLEY Posted: 23.10.2007, 18:38

The following commentary and proposed language for Section A.4 are made on behalf of the Northwest Power Pool Reserve Sharing Group (NWPP RSG). Balancing Authority participants in the NWPP RSG are: AESO, AVA, BCTC, BPAT, CHPD, DOPD, GCPD, IPC, NWMT, PACE, PACW, PGE, PSE, SMUD, SCL, SPPC, TID, TPWR, and WAUW.

INTRODUCTORY COMMENTARY

The Northwest Power Pool Reserve Sharing Group (NWPP Reserve Sharing Group) urges the WECC to include in BAL-STD-002-1 language that not only expressly recognizes Reserve Sharing Groups, but resolves concerns that could undermine the viability of Reserve Sharing Groups if not addressed.

The current version of the standard, BAL-STD-002-0, contains language indicating that when an agent for a Reserve Sharing Group has provided in its data submission a specific identification of Reserve Sharing Group members that are responsible for noncompliance, allocation of penalties will follow the indicated responsibility.

The concept expressed in BAL-STD-002-0 needs to be carried over to the proposed successor standard (BAL-STD-002-1), but it also must be extended and clarified. These comments include the clarifications and proposed language that the NWPP Reserve Sharing Group suggests be made to BAL-STD-002-1. We appreciate WECC's consideration of these comments.

Reserve Sharing Groups enhance reliability while saving costs. This is good for utilities and their customers. A policy to support the operation of Reserve Sharing Groups is already reflected in the current BAL-STD-002-0, as well as the national standard adopted by NERC (BAL-002-0). In order to continue the benefits provided by reserve sharing groups, the proposed changes in the standard are necessary.

The language of the standard must assure members of Reserve Sharing Groups that once specific responsibility for noncompliance has been assigned to the appropriate members of the Reserve Sharing Group, the penalty assessment process will not shift liability to other Reserve Sharing Group members, or make the Reserve Sharing Group act as guarantor for member penalty obligations.

This issue is extremely important to the NWPP Reserve Sharing Group because it encompasses members (such as Canadian Balancing Authorities) that are not subject to FERC enforcement authority with respect to BAL-STD-002, as well as members that may have unresolved issues regarding the imposition of monetary penalties. It is neither appropriate nor feasible to expect this issue to be resolved among the members of the Reserve Sharing Group. Further, many entities have legal prohibitions against their being liable for another entity's penalties or debts.

To illustrate the problem: If the NWPP Reserve Sharing Group as whole had an instance of noncompliance with BAL-STD-002-1, and if the noncompliance were 50% attributable to Canadian Balancing Authorities, it is vital for the standard to clearly provide that the share of monetary penalties that would have been payable by the Canadian Balancing Authorities (which are not subject to monetary penalties under FERC rules) cannot be shifted onto the other Balancing Authorities that bear the remaining 50% of the responsibility (or onto other Reserve Sharing Group members that bear no responsibility).

The critical concepts are that a Reserve Sharing Group (1) must not become an indirect mechanism to impose penalties that could not be assessed directly against a Balancing Authority, and (2) must not shift liability among members of a Reserve Sharing Group in such as way as to cause any Balancing Authority to pay penalties that are greater than its proportionate share of responsibility for an instance of noncompliance.

The language of the standards needs to be clarified in this respect so that it is workable for Reserve Sharing Groups to register as Responsible Entities for purposes of compliance with BAL-STD-002-1. If a Reserve Sharing Group is unable to register for compliance purposes, this would essentially defeat the Reserve Sharing Group's ability to operate for any purpose.

We are providing proposed language to be included in the standard BAL-STD-002-1. We believe this language addresses the concerns and legal issues we have raised while maintaining the standard's requirements for a balancing authority related to reliability of the bulk electric system.

PROPOSED LANGUAGE FOR SECTION A, PARAGRAPHS 4.1 AND 4.2

4. Applicability
4.1 Balancing Authority. This Standard shall apply to a Balancing Authority individually unless the Balancing Authority is a member of a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2.

4.2 Reserve Sharing Group.

4.2.1 This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

4.2.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

4.2.3 If an agent properly designated in accordance with Section 4.2.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 4.2.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 4.2.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

4.2.4 If an agent properly designated in accordance with Section 4.2.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

4.2.5 Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 4.2.2 shall be subject to this Standard on an individual basis.

Response: Please refer to the response to Mike Ryan's comments above.

DON BADLEY Posted: 23.10.2007, 18:42

The following comments and questions related to Sections of BAL-002-WECC-1 are made on behalf of the Northwest Power Pool Reserve Sharing Group (NWPP RSG). Balancing Authority participants in the NWPP RSG are: AESO, AVA, BCTC, BPAT, CHPD, DOPD, GCPD, IPC, NWMT, PACE, PACW, PGE, PSE, SMUD, SCL, SPPC, TID, TPWR, and WAUW.

A. Introduction
Comment regarding title:
• Title should be Contingency Reserve not Contingency Reserves. Contingency Reserve is a category of reserve.

Response: The drafting team has made this change.

B. Requirements
Comments regarding R1.1.2:
• What is the technical justification for the3% quantities used to determine the minimum level of contingency reserve? Why require more than MSSC?
• Don't you mean Net Actual Interchange instead of "interchange"?
• Is behind-the-meter generation to be counted when determining the minimum amount of contingency reserve? What about generation that is not telemetered into AGC?

Response: The technical justification is that this proposal provides a clear requirement without reducing the amount of reserves required in the WECC. When the information from surveys of applicable entities was reviewed, this level of reserve provided a level approximately equal to that calculated under our interpretation of today's rules. The proposed language clarifies issues related to the reserves required for different types of generation, transactions impact on the level of required reserves and others listed in the "Reasons Why Bal-002 – 9-14-07."

While some on the drafting team would agree with moving to only MSSC, the WECC Board of Directors and the majority of the members of WECC voted to include the Tier 1 standard in the filings to NERC and therefore FERC to ensure that the level of reserves did not decrease with the implementation of mandatory standards. The Board of Directors and members in attendance at the OC continue to voice concern over a potential reduction in the level of required reserves in the WECC.

The drafting team has modified the proposed standard to address the issue of "net Interchange" versus "Net Actual Interchange." We have also tried to clarify the language regarding generation.

The drafting team believes that the generation and interchange measured by the Balancing Authority EMS system shall be sufficient for determination of contingency reserve requirements greater than Most Severe Single Contingency. Due to the limited size of non-metered generation, it is not a reliability issue to leave small generators not telemetered into the EMS system out of the equation.

Comment regarding R2:
• Does Requirement R2 mean that BAs within a reserve sharing group are not individually responsible to carry 50% spinning reserve?

Response: Yes, the allocation of reserves among RSG members is not being dictated by this standard. This is a business issue that the RSG members should address rather than having the standard direct how an entity complies.

Comments regarding R2.1:
• Does "initially automatically respond" mean it no longer has to automatically respond after the initial period ends?
• What is the length of the initial period?

Response: The drafting team has revised R2.1 to clarify the intent.

Comment regarding R2.2:
• How does one determine "capable of responding"?

Response: Unit testing, actual unit operation or other means of proving that a unit can provide the response claimed.

Comment regarding R.3:
• These types of reserve must be clearly defined in a way that they can be applied to contingency reserve; this would include a statement about the length of time it would take to deploy the reserve.

Response: The drafting team has clarified that only the amount that can be deployed within 10 minutes can be counted.

C. Measures
Questions regarding M1:
• FERC is opposed to fill-in-the-blank (self reported) data. How will any auditor know whether the data used for analysis is true or false?
• What data is required as documentation?
• Why is the metric based upon data averaged over the clock hour when the standard requires a minimum to be available "at all times"?
• How are we to handle the 105 minute exception when we are keeping records that based upon data averaged over the clock hour?
• Since interchange transactions claimed as a resource for contingency reserve must be added or subtracted to determine the minimum amount of contingency reserve required, how is this do be documented within a reserve sharing group or with BAs outside of the reserve sharing group?

Response: The drafting team does not agree that the measurement data is a fill-in-the-blank issue. All data ultimately comes from the entity. The drafting team does not see any other way than to require the responsible entity to have the data to prove that it met the requirements. The required data that must be provided for an audit is spelled out in the measurement section. The measurement period provided for in the standard is the same that has been used previously. The drafting team recommended that this be maintained. ISSUE OF MEASUREMENT OF RESERVE RESTORATION. The drafting team believes that a tag showing the availability of the reserves would suffice, although a contract with the party in addition to the tag would probably be better.

Questions regarding M2:
• If a BA carries 200% of its required spinning reserve for the first half hour and 0% for the second half hour, does it meet the standard?
• How is the amount of spinning reserve to be determined? Is it that which can be fully deployed in 10 minutes, 1 minute, 30 seconds? Does it have to respond automatically to frequency?

Response: Yes, technically this would meet the requirements, but in reality, it is unlikely that this could be done. Additionally, operating this way would cause the likelihood of failing the DCS requirements to dramatically increase. The drafting team modified the proposed standard to address the time period for the response. NERC has defined spinning reserve, and the drafting team recommends using this definition. In R2, the drafting team has required that spinning reserve be responsive to frequency.

Questions regarding M3:
• Does this mean a record of every source of contingency reserve used to recover from an event must be documented?
• Is it necessary to track the availability as well as the deployment of every type of acceptable reserve?

Response: Recovery from an event is not measured in M3. Rather the amount of reserves that comes from acceptable resources is measured. There is nothing about recovery in this measurement. Documentation should be provided that shows the reserves used to meet the requirement.

Question regarding M3.1:
• What is necessary to demonstrate a declared capacity or energy emergency? A NERC EEA issuance or declaration of emergency? What is the definition of an emergency?

Response: The intent of using capitalized terms in R3 is to require the RC to declare an emergency according to NERC Standard EOP-002. The drafting team has modified the standard to clarify this issue.

D. Measures
Question regarding D1.3:
• What form of record keeping is acceptable – electronic, paper, or both?

Response: Either form would suffice.

General Questions about Compliance
The introductory description of this draft standard states it is “designed to implement the directives of FERC and recommendations of NERC when BAL-002-0 was approved as a NERC reliability standard.” Does this mean that quarterly compliance reports no longer need to be sent to NERC? Are BAs within the WECC still expected to file monthly exception reports regarding Operating Reserve to the WECC to satisfy the requirements in RMS?

Response: The reporting requirements in this standard only pertain to this standard. Reports required by NERC standards are not affected by this standard. The Compliance Monitor in the WECC will determine the reporting requirements. The Compliance Monitor will issue a WECC Compliance Manual that covers all aspects of the reporting requirements. The reporting requirements from the Tier 1 standard would be replaced with the reporting requirements related to this standard when approved.

Are all the Existing Standards (NERC BAL-002, and WECC BAL-002) replaced by this proposed Standard BAL-002-WECC-1? What about the other requirements such as compliance with DCS etc. are they still required? Will there be one place or one Standard that captures all the issues associated with BAL-002?

Response: The WECC Standard will be replaced by this standard. The requirements in this standard will supplement the requirements in the NERC standard, but since the NERC standard has additional requirements not covered by this standard, the NERC standard would still apply as well, just as it does today.

Robert Schwermann Posted: 24.10.2007, 20:11

SMUD appreciates the opportunity to comment, and applauds the work of the Committee for its efforts in addressing these difficult issues. In general, SMUD is supportive of the proposed standard. We support having a higher Contingency Reserve (CR) Requirement for exporting systems than that required for importing systems, as this assigns a greater reserve requirement to the suppliers where the generation is located. In addition we believe that allowing reserve-sharing groups to share CR obligations is a positive improvement, as it provides greater flexibility to utilize available resources. The proposed standard gets rid of much of the confusion that currently exists over Load Responsibility, and eliminates dependence on various Market Products (Firm, Exchanges, and Unit Contingent etc). In addition it eliminates complication over reserve amounts based on type of generation currently Hydro (5%), Thermal (7%), and Wind or Solar (no specified reserve requirements).

Response: Thank you for your supporting comments.

We would like to suggest that R1.2 and R1.3 be clarified to avoid interpretation and application errors. It appears that R1.2 and R1.3, were based on, and are intended to be similar to the existing MORC 1.A.1.c, Additional Reserve for Interruptible Imports and 1.A.1.d, Additional Reserve for on-demand obligations. Both of these additional reserve obligations were originally allowed to be “Non-Spinning” reserves. Although many exporters honored On-demand obligations with in-kind reserves, it is not clear if the intent of R1.2 is to continue this use of in-kind reserves or to include the value in overall Contingency Reserve such that 50% of that amount would be required to be spinning reserve. If a Source Balancing Authority (BA) is claiming an interchange transaction as a Contingency Reserve resource the Source Balancing Authority can only count it as a Non-Spinning resource. As such the receiving BA should only have to maintain non-spinning CR’s for this transaction.

Response: The drafting team has modified the proposed standard to address this issue.

SMUD would also like to sound a cautionary note regarding elimination of the requirement to carry additional reserves for curtailable transactions, as is the effect of R 1.2 . The use of such curtailable

transactions are limited in volume currently primarily because the additional reserve burden required under the current MORC creates a disincentive. Elimination of this reserve burden could significantly increase reliance on curtailable transactions. Should heavy reliance on these types of transactions create a reliability problem, entities relying heavily on such transactions for serving load may have a new most single severe contingency that drives their reserve obligation.
R1.3 uses “slightly” different wording where it is specified that the Source BA must maintain an amount of CR equal to the transaction amount when the Sink BA is claiming the transaction as a resource to meet its “like” CR Requirement. This implies that R1.3 may require either Spinning or Non-Spinning Reserve.

We offer the following wording change:

R1.2 Contingency Reserve for a Sink Balancing Authority, capable of fully responding in 10 minutes, in an amount equal to Interchange Transaction(s) where the Source Balancing Authority is claiming the Interchange Transaction(s) as
a resource to meet its Contingency Reserve requirements.

R1.3 Contingency Reserve, for a Source Balancing
Authority, equal in amount and type, to the capacity transaction(s) where the Sink
Balancing Authority is claiming the transaction(s) as a resource to
meet its Contingency Reserve requirements.

Response: The drafting team has made changes to the proposed standard similar to those proposed by SMUD.

SMUD Coordinated Comments

Mark Willis Posted: 25.10.2007, 12:23

SMUD has previously commented on this standard as a coordinated response from both the Merchant and Reliability divisions of the company. These comments focused primarily on clarifications of the proposed standard to eliminate ambiguity.

SMUD System Operations and Reliability is also submitting separate comments as a Northwest Power Pool member in support of the comments previously made by Don Badley of the NWPP with respect to the potential impact on reserve sharing groups. The comments from the Northwest Power Pool do not conflict with SMUD’s previous submission, but provide more detail and are more applicable to the operation of the Reserve Sharing Group.

In particular, the following items should be considered by the standards drafting team:

• We support clarification of compliance language that ensures responsibility for sanctions is allocated correctly to the individual BA’s members of an RSG, in accordance with the wording changes to Paragraphs 4.1 and 4.2 submitted by the NWPP.

Response: Please refer to the response to Mike Ryan’s comments above.

• Without a technical basis to establish the need for contingency reserve in excess of the MSSC, we feel that although conservative, it is unwise to establish a mandatory and enforceable standard for these arbitrary and additional reserves above and beyond what NERC has considered adequate.

Response: While some on the drafting team would agree with moving to only MSSC, the WECC Board of Directors and the majority of the members of WECC voted to include the Tier 1 standard in the filings to NERC and therefore FERC to ensure that the level of reserves did not decrease with the implementation of mandatory standards. The Board of Directors and members in attendance at the OC continue to voice concern over a potential reduction in the level of required reserves in the WECC.

• The standard should clarify if the availability of reserves can be integrated over an hour or if it must represent a continuous availability.

Response: The drafting team clarified that the measurement of compliance will be the hourly integrated calculation.

• The standard should clarify what delivery time frame is acceptable for “Spinning Reserve” considering the delay in instantaneous deployment due to actions required by operators.

Response: In the proposed standard, R2.1 and R2.2 has been adjusted to clarify the requirements related to Spinning Reserve. The drafting team believes that the revised language is clear in that Spinning Reserve is automatically responsive to a frequency deviation (i.e. without operator intervention) and that the reserves must be fully deployable within 10 minutes.

SMUD - System Operations & Reliability

Brent Kingsford Posted: 29.10.2007, 09:17

The California ISO appreciates the opportunity to comment on BAL-002-WECC-1. This is a critical standard that requires careful attention to detail in drafting. The CAISO requests careful consideration of the following suggestions.

The CAISO believes that there should be greater detail in R2 and its sub-requirements to define spinning reserve. We believe that in order to be counted as spinning reserve the resource not only “Initially automatically responds to frequency deviations “but need additional details to ensure the quality of the reserves. We believe that there needs to be greater detail in the requirement as to frequency responsiveness for Spinning Reserve qualifying for Contingency Reserve.

Response: The drafting team has reviewed and revised the language in R2.1 and R2.2.

We would like to suggest a 0.36 Hz Dead-Bandwidth and a response rate that is inversely proportional to the magnitude of frequency deviation, essentially the same benefit that the 5% droop characteristic achieved.

Response: The drafting team does not feel that this should be included in the proposed standard as it is beyond the scope of this standard. It is possible that it would be more appropriate in another standard at NERC or WECC regional criteria.

There needs to be a requirement detailing the duration a resource counted as Contingency Reserve must be available once deployed. While the CAISO uses 2 hours, we recognize that not all entities would want to require the resource to be available for this full time period. We would suggest that an appropriate time would be 105 minutes to coincide with disturbance recovery time. It would also be appropriate to designate in some method that a fast, fully responsive, yet energy-limited resource may be replaced or combined with a slower-responding, energy-abundant resource in a manner that achieves adequate response that is both timely and long-lasting enough to meet this and all other requirements.

Response: The drafting team believes that this issue is best addressed by each individual entity that is required to meet the NERC DCS requirements and the WECC Contingency Reserve requirements.

There needs to be details included in the M1 that details what intervals are appropriate for attaining the clock hour average of reserves. Is the appropriate measure at the AGC scan rate, a one minute interval, or a twice an hour measure? Without the appropriate detail included in the standard, a BA would be left to choose a measure that would be best for their compliance rather than a "standard" measurement.

Response: The drafting team believes that the proposed language in M1 is clear.

In addition, The CAISO could not implement this proposal from a settlement perspective until after MRTU go live on March 31, 2008. Moreover, to ensure CAISO readiness, a 90 day advance written notice is needed.

Response: The Implementation Date for this standard will be the first day of the quarter following regulatory approval. Based on the current timeline, this is unlikely to happen prior to the last quarter of 2008.

California ISO

Tom Cooper

Salt River Project

A few questions for the drafting team:

When does the 10-minute measurement period begin for spinning and non-spinning reserves (i.e., is it 10-minutes following a contingency, 10-minutes following notification, or some other starting point)?

Response: The 10 minutes is from notification. The drafting team has clarified this in the standard.

How would the requirement that spinning reserve be automatically responsive to frequency deviations be measured for compliance?

Response: The drafting team has clarified the Measurement and Compliance Sections of the standard.

Is it the intent of the proposal that, for the purpose of operating reserve, the concept of non-firm transactions is eliminated, i.e. all generation has to carry some amount of reserves?

Response: Since the use of the term non-firm mixes reliability and commercial products, the concept of this type of transaction has been removed from the determination of reserve requirements. The issue is covered in Requirement R1.2 in that if the source claims that the energy could be recalled for an event in the source BA Area, the sink would have an obligation to increase its non-spinning reserve in an amount equal to the transaction. Requirement R1.1 would require that the source BA increase its contingency reserve requirement by 3% of the sale for the recallable sale.

Is it the intent of the proposal that an entity with on-demand contract obligations is no longer required to carry operating reserves to cover those obligations until the obligation is called on, at which point it might become generation with the 3% requirement?

Response: No, refer to the revised Requirement R1.3.

Thank you for considering these questions.

Greg Lange
Grant County PUD

As Grant has commented during the discussions on BAL-STD-002-0, we are not at all apposed to changing the way reserves are handled in the west. There are several issues that need cleaning up. We just would like to see us quit working on temporary fixes and get moving on the Board approved Frequency Responsive Reserves (FRR) process in combination with the MSSC as the most technically defensible backstop that we have. We would like to see one change for the better, not multiple changes. Especially when they don't look and feel anything like what the FRR will look like. Each temporary change comes with unnecessary added costs. In the Northwest we not only have to modify our individual EMS and Accounting programs, but we also have a very sophisticated automatic reserve sharing program that will need changes for each change in reserves we make. We would like to make those changes once and get on with it.

Response: The FRR standard is being worked on in parallel with this proposed standard. In the event that it is adopted prior to this standard, this standard would likely be dropped. However, due to the time constraints of the Tier 1 replacement requirements that WECC and FERC expects, this standard must continue through the process.

The other major heartburn we are having with this proposal is that it still does not take care of the NERC requirement to have a technically defensible standard. We still will have arbitrary percentages, which will be placed half on load and half on generation. This may help everyone feel better, but is still no more technically defensible than what we have today.

Response: The technical justification for this standard is that this proposal provides a clear requirement without reducing the amount of reserves required in the WECC. When the information from surveys of applicable entities was reviewed, this level of reserve provided a level approximately equal to that calculated under our interpretation of today's rules. The proposed language clarifies issues related to the reserves required for different types of generation, transactions impact on the level of required reserves and others listed in the "Reasons Why Bal-002 – 9-14-07."

This current proposal still leaves interpretation up to the individual entities for what is generation. So we believe we will still have the same loopholes we have today. There is generation behind meters, IPP's are still reluctant to give accurate forecasts to their BA's and there is still generation that is not telemetered into an AGC system and thus hard to determine.

Response: The drafting team believes that the generation and interchange measured by the Balancing Authority EMS system shall be sufficient for determination of contingency reserve requirements greater than Most Severe Single Contingency. Due to the limited size of non-metered generation, it is not a reliability issue to leave small generators not telemetered into the EMS system out of the equation.

Until we create the technical defensible amount of reserves needed for the health of the interconnection under reasonable circumstances and that number is allocated to the BA's in the interconnection there will be no solution to this problem.
Grant would like to see us abandon these temporary efforts and concentrate on getting to the long term solution that reasonably protects the Western Interconnection infrastructure and its customers and truly eliminates the ambiguities in the system today.

Response: While some of the drafting team may agree with this position, the fact is that the FRR standard is not yet supported by a majority of the WECC members for the purposes of implementing an enforceable standard. Until questions related to the measurement processes, duration of measurement, and other basic issues are answered, the FRR standard will not be implemented in the WECC.

Chris Turner
Seattle City Light

Seattle City Light appreciates the opportunity to respond and also appreciates all the hard work put into developing this version of the standard.

Instead of repeating many of the comments that have already been made, City Light would like to point out two issues of note and then echo comments made by the NWPP.

Issue 1: What is the technical basis for changing to a reserve of 3% of the BA load and 3% of the net generation? (R1.1.2). A change from the existing percentages to new percentages should be driven by a defensible technical methodology.

Response: The technical justification for this standard is that this proposal provides a clear requirement without reducing the amount of reserves required in the WECC. When the information from surveys of applicable entities was reviewed, this level of reserve provided a level approximately equal to that calculated under our interpretation of today's rules. The proposed language clarifies issues related to the reserves required for different types of generation, transactions impact on the level of required reserves and others listed in the "Reasons Why Bal-002 – 9-14-07."

Issue 2: With a frequency responsive reserve standard on the horizon, this standard seems to be mis-timed. Instead of making two many major changes of this type close together (especially since the current requirements have served us well) we should wait for the FRR standard to play out.

Response: The FRR standard is being worked on in parallel with this proposed standard. In the event that it is adopted prior to this standard, this standard would likely be dropped. However, due to the time constraints of the Tier 1 replacement requirements that WECC and FERC expects, this standard must continue through the process.

Comment: If this standard moves forward to a vote, City Light would like to echo and repeat proposed language changes previously made by the NWPP. These are:

PROPOSED LANGUAGE

4. Applicability

4.1 Balancing Authority. This Standard shall apply to a Balancing Authority individually unless the Balancing Authority is a member of a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2.

4.2 Reserve Sharing Group.

4.2.1 This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

4.2.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

4.2.3 If an agent properly designated in accordance with Section 4.2.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 4.2.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 4.2.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

4.2.4 If an agent properly designated in accordance with Section 4.2.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified

Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

4.2.5 Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 4.2.2 shall be subject to this Standard on an individual basis.

Response: Please refer to the response to Mike Ryan's comments above.

Thank you for the opportunity to comment on this standard.

Scott Kinney
AVA

Avista submits the following comments on the proposed BAL-002-WECC-1 standard.

As a member of the NWPP Reserve Sharing Group Avista agrees with the comments submitted by the NWPP RSG to ensure the benefits of participating in a RSG continue forward under the new standard. Here is the proposed language much of which is in the current standard.

4. Applicability

4.1 Balancing Authority. This Standard shall apply to a Balancing Authority individually unless the Balancing Authority is a member of a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2.

4.2 Reserve Sharing Group.

4.2.1 This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

4.2.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

4.2.3 If an agent properly designated in accordance with Section 4.2.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 4.2.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 4.2.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

4.2.4 If an agent properly designated in accordance with Section 4.2.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

4.2.5 Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 4.2.2 shall be subject to this Standard on an individual basis.

Response: Please refer to the response to Mike Ryan's comments above.

B. Requirements

R.1.1
With the continued focus on developing and implementing an FRR standard Avista does not see the need to change from the current contingency reserve requirement of 5% and 7% at this time. Again there is no technical basis for the new 3% requirement. Why not base the requirement on the NERC standard of MSSC or twice MSSC?

Response: The technical justification for this standard is that this proposal provides a clear requirement without reducing the amount of reserves required in the WECC. When the information from surveys of applicable entities was reviewed, this level of reserve provided a level approximately equal to that calculated under our interpretation of today's rules. The proposed language clarifies issues related to the reserves required for different types of generation, transactions impact on the level of required reserves and others listed in the "Reasons Why Bal-002 – 9-14-07."

The FRR standard is being worked on in parallel with this proposed standard. In the event that it is adopted prior to this standard, this standard would likely be dropped. However, due to the time constraints of the Tier 1 replacement requirements that WECC and FERC expects, this standard must continue through the process.

R.2.1
What is meant by initially automatically responds to frequency deviations?

Response: Please refer to the response to Tom Cooper.

C. Measures

M1 through M3
Need more clarity and definition around what data is required and how is it to be determined.

Response: The drafting team has clarified the measurement section.

Gregg Travis

I would like to thank the standard drafting team for its hard work. I have an appreciation for the difficulty of this task and the level of commitment and perseverance required.

My comments are in recognition of the diverse make up of the Western Interconnection and specifically the northwest which is comprised of public and private as well as U.S. and Canadian entities. Please consider the following:

It would be helpful if BAL-002-WECC -1 contained language that clarifies the allocation of penalties to Reserve Sharing Groups. Specifically, it could state clearly how penalties will be handled if allocated to Reserve Sharing Group members that are not obligated by law (statute or regulation) to pay. Idaho Power, an IOU, would prefer the addition of language that states parties responsible for causing or contributing to an event of noncompliance by the Reserve Sharing Group are solely responsible for paying its allocated share of any resulting penalties and neither the Reserve Sharing Group nor any member of the Reserve Sharing Group can be required to pay any penalties allocated to another member.

The following was drafted by NWPP members as language that addresses our concerns.

PROPOSED LANGUAGE

4. Applicability

4.1 Balancing Authority. This Standard shall apply to a Balancing Authority individually unless the Balancing Authority is a member of a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2.

4.2 Reserve Sharing Group.

4.2.1 This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

4.2.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

4.2.3 If an agent properly designated in accordance with Section 4.2.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing

Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 4.2.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 4.2.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

4.2.4 If an agent properly designated in accordance with Section 4.2.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

4.2.5 Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 4.2.2 shall be subject to this Standard on an individual basis.

Response: Please refer to the response to Mike Ryan's comments above.

Anita Lee, P. Eng.
Manager, Operating Policies and Procedures
Alberta Electric System Operator (AESO)

The AESO appreciates the opportunity to comment on the WECC proposed changes to BAL-002-WECC-1. Our comments are as follows:

1. The AESO supports the comments submitted by the NWPP Reserve Sharing Group.

Response: Please refer to the response to Mike Ryan's comments above.

2. The AESO is also concerned of the lack of technical explanation and risk/impact assessment for a couple of fundamental changes to the contingency reserve requirements: a) in R1 - changing to the sum of 3% load and 3% net generation, from the current 5% of the load responsibility served by hydro generation and 7% of the load responsibility served by thermal generation, b) in M1 - changing the time period when the contingency reserve must be re-established to 105 minutes from the current 60 minutes.

Response: The technical justification for this standard is that this proposal provides a clear requirement without reducing the amount of reserves required in the WECC. When the information from surveys of applicable entities was reviewed, this level of reserve provided a level approximately equal to that calculated under our interpretation of today's rules. The proposed language clarifies issues related to the reserves required for different types of generation, transactions impact on the level of required reserves and others listed in the "Reasons Why Bal-002 – 9-14-07."

On the reserve restoration time issue, the WECC Performance Work Group performed studies in 2005 that shows little if any increase in risk to the system by changing the restoration period to the NERC time. Therefore, the drafting team is recommending that the WECC adopt the NERC time period.

3. The AESO recommends that the WECC continues the use of the 5% hydro and 7% thermal requirement, in conjunction with the WECC Board approved interpretation on Load Responsibility, until the WECC moves to an FRR standard.

Response: The proposed language clarifies issues related to the reserves required for different types of generation, transactions impact on the level of required reserves and others listed in the "Reasons Why Bal-002 – 9-14-07." One issue that is clearly not covered by the existing reserve language that would be covered under the proposed language is the proliferation of renewable generation resources that are neither thermal nor hydro. Therefore, these generation resources have no reserve requirements under the current WECC standard.

Anita Lee, P. Eng.
Manager, Operating Policies and Procedures
Alberta Electric System Operator (AESO)

In measure M2, I suggest a wording change: "The Reserve Sharing Group or Balancing Authority has documentation that it maintained at least 100% of required Contingency Reserve levels..."

A similar insertion of "at least" should occur in M2, just before "100%."

Response: The drafting team has made this modification.

Measure M3 should be removed. The key here is performance (i.e., compliance with NERC BAL-002 [DCS], not the process (i.e., what kind of reserves are used).

Measure M3.1 should be promoted to M3.

Response: The drafting team disagrees with this proposed change. There is a requirement to use acceptable reserves to meet R1. Therefore, the measurement is to ensure that the correct form of reserves was used, not to see if an entity met its DCS requirements.

Jay Campbell
Staff Engineer
Electric System Control Center
Sierra Pacific Power Co.

We would like to say thank you for the opportunity to express our opinion concerning the proposed Contingency Reserves business practice BAL-002-WECC-1.

All of the work that was put into this proposal is appreciated and you should be commended for your effort.

Response: Thank you for your support.

As PGE Merchant we realize there has been a tremendous amount of concern over the years of who should be responsible for providing reserves and what amount is appropriate. Arguments have been presented that reserves should be defensible and easy to implement. In addition, arguments have also been made that reserves are being held in one area which would be impossible to call upon if an event occurred due to various constraints.

We agree with those who stated prior that it doesn't make sense to make changes for the sake of change and we would have to develop new processes, and associated standards, again once FRR is implemented. We note that Frequency Responsive Reserve has an identified regional criteria and field test time line which was presented to the Reliability Policy Issues Committee on August 30, 2007.
We are concerned that the potential for complex system modifications and associated costs do not appear to have been considered. Also, the proposed standard does not solve the issue of reserves in other areas since a compromise is proposed and there are still reserves spread all over. This proposal doesn't seem any more defensible than the present 5% and 7% and seems more of a change for the sake of change and not a real fix.

We believe that we need to stop creating partial solutions and focus on coming up with a long term solution that solves all of the issues and not create another band-aid.

Response: The proposed language clarifies issues related to the reserves required for different types of generation, transactions impact on the level of required reserves and others listed in the "Reasons Why Bal-002 – 9-14-07." One issue that is clearly not covered by the existing reserve language that would be covered under the proposed language is the proliferation of renewable generation resources that are neither thermal nor hydro. Therefore, these generation resources have no reserve requirements under the current WECC standard.

The FRR standard is being worked on in parallel with this proposed standard. In the event that it is adopted prior to this standard, this standard would likely be dropped. However, due to the time constraints of the Tier 1 replacement requirements that WECC and FERC expects, this standard must continue through the process.

Bill Casey
Portland General Electric

Comments for BAL-002-WECC-1
Submitted by: Tri-State Generation and Transmission Association, Inc. (Duane Helderlein and Dan Walter)

• Overall, the concepts and rewrite of this standard is appealing. The work group has laid out a nice starting point to debate the pros and cons of this topic, hopefully with the outcome to eliminate ambiguity related to transactions and their impact (or proposed removal of impact) on the determination of contingency reserve requirements and eliminates the need to define requirements for non-hydro and non-thermal generating resources.

Response: Thank you for the support.

•	Clarification is required regarding the contingency reserve calculation which is based upon net generation inside the Balancing Authority (BA). Does net generation apply to the physical generation inside the BA? Or, the electrically metered generation inside the BA? For example, if a generator owner owns generation remote to it's physical BA boundary, however, schedules and tags their ownership share of the generator from the physical location of the generator to their physical BA system, and upon the loss of resource, the generator owner's share is immediately reduced (their share not covered by the reserve sharing group in which the unit physically resides), then does the generator owner, or the BA where the generator physically resides, calculate 3% of the generation for their contingency reserve requirement?

Response: The drafting team believes that the standard is clear. All generators are considered to be part of a Balancing Authority under NERC rules. A generator could be considered part of multiple Balancing Authorities under certain conditions, such as partial units being moved from one BA to another through the use of a pseudo-tie arrangement. Units moved from one area to another through these arrangements would move the unit (or partial unit) into the sink Balancing Authority. If the generation is moved from one BA to another through the use of an Interchange Transaction (dynamic schedule or otherwise), it would not be considered part of the Sink Balancing Authority's generation.

•	Although this would diminish one of the objectives of the current draft (eliminate transaction ambiguity), if under current R.1.1.2. if "Load Responsibility" was inserted for "load", can you explain the impacts of this change and how it would either be a net benefit or drawback to the current proposed language?

Response: Due to the issues surrounding the definition of Load Responsibility and then the definitions of firm and interruptible transactions, the drafting team feels that the term Load Responsibility is not clear or usable for a permanent standard. Additionally, with the historic "understanding" of the term, all parties would benefit from not using this term. It also causes the reserves to move around based on day-ahead and real-time transactions, which hinders the ability of Reliability Coordinators to determine where reserves are held and if that could cause a reliability issue. For these reasons, the drafting team does not believe that using the Load Responsibility term in the future benefits the need for reliability in the WECC.

B. Requirements

R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain as a minimum, Contingency Reserve, of which, at least half must be Spinning Reserve, that is the sum of the following: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R1.1. The greater of the following:

R1.1 R1.1.1. An amount of reserve equal to the loss of the most severe single contingency; or

R1.2 R1.1.2. An amount of reserve equal to the sum of three percent of the Balancing Authority load (net actual generation minus net actual Interchange) and three percent of net actual generation.

R3. R1.2. The Source Balancing Authority An amount of Non-Spinning Contingency Reserve Interchange Transaction(s), for a Sink Balancing Authority, shall increase their Non-Spinning Contingency Reserve by the amount equal to the Interchange Transaction(s), adding to the obligation as calculated in R1. where the Source Balancing Authority is claiming the Interchange Transaction(s) as a resource to meet its Contingency Reserve requirements.

R4. R1.3. The Source Balancing Authority An amount of Non-Spinning Contingency Reserve Transaction(s), for a Source Balancing Authority, shall increase their Non-Spinning Contingency Reserve by the amount equal to the capacity transaction(s), adding to the obligation as calculated in R1. where the Sink Balancing Authority is claiming the transaction(s) as a resource to meet its like Contingency Reserve requirements.

R5. The Source Balancing Authority of Spinning Contingency Reserve Transaction(s), for a Source Balancing Authority, shall increase their Spinning Contingency Reserve by the amount equal to the capacity transaction(s), adding to the obligation as calculated in R1.

R2. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of The Contingency Reserve component in R1.1 that is Spinning Reserve, which shall meet the following requirements. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]

R2.1. Initially automatically responds to frequency deviations.

R2.2. Capable of fully responding within ten minutes

R6. R3. Each Reserve Sharing Group or Balancing Authority shall use the following acceptable types of reserve to meet R1.1: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

R6.1. R3.1. Spinning Reserve

R6.2. R3.2. Interruptible Load;

R6.3. R3.3. Interruptible exports;

R6.4. R3.4. Reserve held by other entities by agreement;

R6.5. R3.5. An amount of off-line generation which can be synchronized and generating within 10 minutes; or

R6.6. R3.6. During Capacity and/or Energy Emergencies, Reserve Sharing Group or Balancing Authority may utilize Load.

C. Measures

M1. The Reserve Sharing Group or Balancing Authority has documentation that it maintained 100% of required Contingency Reserve levels based upon data averaged over each clock hour except within the first 105 minutes (15 minute Disturbance Recovery Period, plus 90 minute Contingency Reserve Restoration Period) following an event requiring the activation of Contingency Reserves. For each hour Reserve Sharing Group or Balancing Authority shall have and provide upon request the Contingency Reserve Requirement in MW, how the requirement was calculated, and amount of Contingency Reserve available in MW.

Response: The drafting team adopted one of the proposed changes and made multiple other changes similar to what you have proposed. Please review the revised draft for clarification on most of these items.

Bart McManus - BPAT
Brenda Anderson - BPAP

Bonneville Power Administration is in support of this standard.

BPA prefers to have an FRR standard, but until an FRR standard gets through the standards drafting process and is FERC approved, we believe the 3% load plus 3% generation (3 and 3) concept for contingency reserve obligation is a reasonable replacement of the current standard and its associated ambiguities. Although the 3 and 3 is not technically justified, it does retain the current level of reserve being carried under the current standard. The 3 and 3 also addresses the issues that exist today with the current standard by removing transactions from the calculation of contingency reserve responsibility.

Under CRITF, all transactions will need to be tagged with the responsible entity for contingency reserve as well as the percentage required on each transaction. This will create an undue burden on scheduling for market participants. Including contingency reserve with energy has caused a lot of confusion. The 3 and 3 eliminates the confusion and the additional burden that will be put on the market participants by CRITF.

Under the current standard and CRITF NWPP participants carry 5% CR for wind resources and southern WECC members carry 7%. For transactions from the north to the south, the amount of reserve to be carried on wind is unknown so the tag author will not know which amount to put in that field on the tag. The 3 and 3 will remove this issue.

Another issue in WECC is a misunderstanding concerning deployment of reserve versus the allocation of contingency reserve. Carrying a small percentage of a transaction does not move the DCS requirement from the source to the sink BA. Under the current standard many WECC members believe that contingency reserve obligation equates to DCS recovery. By removing the link to individual transactions when calculating contingency reserve obligation, the 3 and 3 will insure that it only determines the allocation without moving the DCS responsibility.

Response: Thank you for your support.

BPA would like to see the following modifications to the standard.

BPA is in agreement with the comments by other NWPP members concerning language on Reserve Sharing Groups. Clarification is needed for RSGs in the document.

Response: Please refer to the response to Mike Ryan's comments above.

BPA agrees with moving from the current 60 minute recovery of contingency reserve to NERC recovery period of 90 minutes from the end of the DCS recovery period. This should be spelled out as 90 minutes rather than the 105 minutes that is in the current draft.

Response: The drafting team has clarified this language.

Bart McManus - BPAT
Brenda Anderson - BPAP

PPL EnergyPlus appreciates the opportunity to comment on replacement of BAL-STD-002-0. Our comments are focused primarily on clarifications of the proposed standard and are intended to eliminate ambiguity.

B. Requirements
R1.1.2 - Is Balancing Authority load determined from actual or scheduled net generation and interchange? The Contingency Reserve requirement is currently calculated from scheduled generation and interchange. The requirement should be clarified to specify that the calculation is based on scheduled, not actual, net generation and net interchange because the actual amounts are not known until after the fact.

Response: The Requirements are based on actual loads and actual generation inside the Balancing Authority. Interchange Transactions should not impact these numbers directly. If a generator is inside the BA and generating 500 MW at that moment, the reserve requirement is 3 percent of 500 MW. If the load is 600 MW inside the BA, the reserve requirement is 3 percent of 600 MW. Total reserve requirement for this BA would be 33 MW unless its Most Severe Single Contingency is greater than 33 MW.

R1.2 and R1.3 - Do these requirements exclude [?] Contingency Reserves for the Source or Sink Balancing Authorities to be held in Intermediate Balancing Authorities that are neither the source nor the sink?

Response: There would not be any intermediate Balancing Authorities under the proposed rules. The Source is where the energy is coming from under R1.2 and under R1.3 where the capacity is held. There cannot be an intermediate BA holding the reserves under the proposed rules.

R3.5 - Is there a valid reason to keep the requirement for off-line generation to be synchronized and generating within 10 minutes, or could it be increased to 15 minutes to match the NERC requirement for Contingency Requirement?

Response: These are two different requirements. The NERC requirement is to meet DCS in 15 minutes. The WECC requirement is to limit the amount of reserves that can be held on a single unit to what it can move in 10 minutes. In theory, this allows for 5 minutes for the notification to be made to other members of an RSG and then they have a full 10 minutes to move generation.

C. Measures
M1 and M2 - Is the change to 105 minutes intended to match the NERC standard of 15 minutes for the Disturbance Recovery Period plus 90 minutes for the Contingency Reserve Restoration Period? If so, would it be helpful to add such definition to the standard?

Response: The drafting team has modified the proposed language.

D. Compliance
1.4 Additional Compliance Information - The current WECC Standard BAL-STD-002-0 references a Sanction Table. Will the proposed Standard BAL-002-WECC-1 have a similar table? What will be the guide for non-compliance sanctions?

Response: The sanction table that will be utilized in the revised standard will be the NERC Sanction Table. The sanction table is not included in each standard but is available from NERC as well as documents that explain the sanction process.

2. Violation Severity Levels - Violation Severity Levels 2.1 and 2.2 state that it is the Balancing Authority or Reserve Sharing Group's "Contingency Reserve" that must meet certain parameters. Should Violation Severity Level 2.3 and 2.4 also be using "Contingency Reserve" instead of "Operating Reserve?"

Response: Yes, the drafting team has made this correction.

General Questions:
Does the absence of Regulating Reserve language mean that WECC intends to either default to the NERC Standard BAL-005-0 or will adopt a companion WECC standard in the future?

Response: NERC Standards BAL-001 and BAL-005 cover all current requirements that are in the existing WECC standard. Therefore, the drafting team has removed all reference to the regulating requirements.

Thank you for the opportunity to comment. PPL EnergyPlus looks forward to commenting further regarding this drafting process of Standard BAL-002-WECC-1.

Jon Williamson
PPL EnergyPlus

Chelan County would like to add our support for several of the arguments made by others which we believe to have significant merit.

1) We support the comments submitted by the NWPP Reserve Sharing Group.

Response: Please refer to the response to the NWPP comments above.

2) We support the idea of delaying any significant modification (read expensive) to the reserve sharing allocation unless it moves us in the direction of a technically defensible standard.

Response: Please refer to response to comments Scott Kinney and others above.

3) We support the insertion of language in this standard that definitively removes the concept of Joint and Several Liability for members of a Reserve Sharing Group where responsibility for any liability for non-compliance has been fixed by the RSG or its authorized agent. Several NWPP member commentors have included proposed text.

Response: Refer to the response to Mike Ryan above.

John Appel
Chelan PUD

TID also appreciates the work of the drafting team. This is a difficult subject and any changes are likely to have intended and unintended consequences.

TID supports the language submitted by the NWPP RSG regarding the allocation of responsibility to individual Balancing Authorities within a Reserve Sharing Group. BA's that do not contribute to a violation should not be saddled with any penalties.

Response: Refer to the response to Mike Ryan above.

TID agrees with other comments regarding the need to justify reserves in excess of the MSSC. Furthermore, the requirement to hold 50% of Contingency Reserves as spinning reserve should also be examined and justified. In some applications, it appears to be an unnecessarily generalized requirement. Some areas may need spinning reserve to remain stable after certain contingencies. In other areas, such a requirement may not be required.

Response: Please refer to the response to Don Badley and Scott Kinney above.

With regard to R1.1 and R1.2, it should be clear that any such claim should be substantiated by the appropriate designation on an e-tag. Absent designation on the e-tag, minimum Contingency Reserve associated with R1.2 and R1.3 shall equal 0.

Response: The drafting team believes this is covered under the measurement section of the standard. Modifications have been made to clarify the measurement.

I believe the list of acceptable types of reserve listed under R3 applies to meet R1, not just R1.1. (Those reserves are also utilized for R1.2 and R1.3 as well.)

Response: The drafting team agrees and has made this modification.

In calculating reserves under M1, shall each component of the reserve determination be averaged over each clock hour? Shall any and all clock hours that include the 105 minutes after a contingency be excluded from the calculation?

Response: The drafting team has clarified this section.

I believe M3.1 may be more clear if it refers to a BA requesting that its RC declare a Capacity or Energy Emergency. In some parts of the NERC standards, it appears that only a RC can declare such an Emergency.

Response: The drafting team has clarified this section.

In determining the Violation Severity Levels, it should be clear that one occurrence refers to the average of Contingency Reserve for one hour, not one instant in time.

Response: The drafting team has made this clarification.

I also suggest that the severity level should reflect the reliability impacts of the infraction. For example, a 25 MW shortfall in Contingency Reserve would be unlikely to have a moderate affect on reliability. Accordingly, I would suggest that any violation of less than 25 MW be considered no more than a Lower Level Violation. Similarly, a violation of 50 MW or less would be considered no more than a Moderate level of non-compliance. Lastly, I would suggest that a violation of 75 MW be considered no more than a High Level of non-compliance. The MW values chosen may not be the most appropriate but are used for illustrative purposes.

By way of an example, under the proposed standard, a BA with a 1000 MW MSSC could be 100 MW deficient and have a lower severity level (Lower) than a BA with a 100 MSSC and a 25 MW deficiency (High). I believe such a result is not commensurate with the reliability impacts to the interconnection.

Response: Due to the varying sizes of Balancing Authorities and Reserve Sharing Groups, the drafting team believes that the percent of required reserves is a better measure than a straight MW number. Additionally, the compliance monitor will have discretion in adjusting the sanction based on the size of the entity involved.

TID appreciates the opportunity to provide its comments.

Jim Farrar
Phone 209 883 8210
Fax 209 656 2147

PacifiCorp Commercial and Trading (PacifiCorp Merchant) submits the following comments in support of the draft "WECC Standard BAL-002-WECC-1 Contingency Reserves". PacifiCorp Merchant believes the proposed standard relieves ambiguity created by the current standard and fairly allocates reserve amounts based on the type of generation. PacifiCorp Merchant also believes additional safeguards exist to eliminate any threat to reliability caused by any possible reduction in available reserves due to the proposed changes. Finally, PacifiCorp Merchant believes the proposed change to the Reserve Restoration Period provides a more practical period than the current requirement.

The proposed standard eliminates the confusion that currently exists over the definition and implementation of the defined term "Load Responsibility." By eliminating Market Products (Firm, Exchanges, and Unit Contingent, etc.) from the load responsibility calculation, clarity of contingency reserve obligation is greatly enhanced.

The proposal eliminates the arbitrary allocation of contingency reserve amounts based on type of generation, currently hydro (5%), thermal (7%), and wind (5%) or solar. While a 3% load / 3% generation split may result in a lower level of contingency reserve obligation for the interconnection, it is also likely that, through clarity in the calculation, contingency reserve obligations currently unmet will be remedied resulting in additional contingency reserve held within the interconnection. Although there is no technical basis for the 3% load / 3% generation split, there has never been a technical basis for the current 5% hydro / 7% thermal split.

The Disturbance Control Standard (DCS) provides some built-in protection against insufficient contingency reserve. If implementation of the proposed standard results in the balancing authority's inability to recover from contingencies under the new allocation, the DCS ensures documentation of this failure and the balancing authority will adjust its own reserve requirement to carry additional future contingency reserve . Were this phenomenon endemic throughout the interconnection, the reliability work groups and the operating committee has the ability to act quickly to adjust the 3%

load / 3% generation allocation accordingly.

Response: The drafting team appreciates these comments in support of the proposed standard.

Don Badley, on behalf of Northwest Power Pool members, has submitted proposed language for section A, paragraphs 4.1 and 4.2. PacifiCorp Merchant seconds the concern that the standard must explicitly identify the Reserve Sharing Group member's rights and obligations, and supports the comments of the NWPP in this matter.

Response: Please refer to the response to Mike Ryan's comments above.

Changing the Reserve Restoration Period from 60 minutes to 105 minutes is also an important enhancement. Currently, when contingency reserves are activated mid-hour, the reserves must be restored within 60 minutes, ending mid-hour. With almost universal block-hour scheduling in the Western Interconnection, reserve restoration mid-hour can be cumbersome and can jeopardize the balancing authority's responsibility to maintain appropriate contingency reserves at all times. The proposed change would allow sufficient time to allow for restoration regardless of when during the current hour the situation arose, thus greatly alleviating these problems.

Response: This is one of the main reasons for the recommended changes. The second reason is that there is no material impact to system reliability as determined by studies done by the WECC Performance Work Group. Finally, this complies with the existing NERC requirements.

Thank you for the opportunity to comment.

Michael Reid
PacifiCorp C&T

The following comments were posted by WECC staff on behalf of Leland McMillan of NorthWestern Energy.

NorthWestern Energy (NWMT) supports the following changes to BAL-WECC-002-1 as proposed by the NWPP.

PROPOSED LANGUAGE FOR SECTION A, PARAGRAPHS 4.1 AND 4.2

4. Applicability

4.1 Balancing Authority. This Standard shall apply to a Balancing Authority individually unless the Balancing Authority is a member of a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2.

4.2 Reserve Sharing Group.

4.2.1 This Standard shall apply to a Reserve Sharing Group that has registered with the WECC as provided in Section 4.2.2, and each Balancing Authority identified in the registration shall be responsible for compliance with this Standard through its participation in the Reserve Sharing

Group and not on an individual basis.

4.2.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC (a) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, (b) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and (c) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

4.2.3 If an agent properly designated in accordance with Section 4.2.2 identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance, (a) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, (b) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection (a) of this Section 4.2.3, and (c) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection (a) of this Section 4.2.3 (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

4.2.4 If an agent properly designated in accordance with Section 4.2.2 fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

4.2.5 Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Section 4.2.2 shall be subject to this Standard on an individual basis.

Response: Please refer to the response to Mike Ryan's comments above.

In addition to the above changes, NWMT does not agree with the proposal as currently described in R.1.1.2. The 3% of load and 3% of generation, besides having no sound technical justification, is too complicated and will be difficult to monitor, verify and report. NWMT recommends that, through changes to R1.1.2., the standard incorporate the interpretation of load responsibility as recently approved by the WECC Board of Directors. For example, R1.1.2. could be changed as follows:

R1.1.2. An amount equal to 6% of the Balancing Authority's Load Responsibility.

Response: The term Load Responsibility causes problems today and would likely continue to do so into the future if we leave it in the standard. Additionally, it is unreasonable to continue to base reserve requirements on market products. The drafting team feels that the reliability standard should not be based on market products, which is what happens with the Load Responsibility definition that exists today. Reliability Coordinators are unable to forecast where reserves will reside, most Balancing Authorities are unable to decide what will be needed due to the separation between markets and transmission and finally there is no way to ensure that definitions that cover today's market products will cover those of tomorrow. In order to make progress and insure that the reliability of the system is maintained, the WECC reserve requirements must be separated from the market products. Please refer to the other posted documents for a more complete discussion of these issues.

NWMT supports the 105 minute time value included in M.1. and M.2.

Response: Thank you for your support.

Leland McMillan
NorthWestern Energy

Below are Dynegy's comments to the draft Contingency Reserve Standard BAL-002-WECC1.

First, we would like to express our concern regarding changing the existing reserve requirement from load based to a combination of load and generation based. In our view this would lead to a major cost shift in several areas in the west, especially for Generation-Only Control Areas. Under the proposed standard, the Generation-Only Control Areas would be required to carry 3% reserves whenever they are operating, something that they do not have to do today.

In addition, though the standard design team has maintained that, in their view, WECC is not responsible for the actions of different Balancing Authority and Reserve Sharing Groups regarding cost assignment associated with reserve requirements, we believe that this proposal may result in incentivizing actions on behalf of BAs and Reserve Sharing Groups that would results in imposing additional burden on IPPs for carrying reserves (that they do not have to do today). Unlike a Load Serving Entity, an IPP has no mechanism to recover these additional costs. In an economically efficient market, a generator would eventually be compensated as well, if required, but that transparency does not exist in the Northwest or Southwest of WECC specifically. The markets in WECC are not efficient specifically for reserves and this unduly burdens generators. Furthermore, we do not believe that the white paper justifies this action or quantifies its benefits. As such, we recommend that the Standard Design Committee revisit this issue of changing the reserve from a load based to a combination of load and generation based. Further, should the design team decide not to accept our recommendation, we request that the design team provide a justification that is based upon technical facts. Finally, the design team must address the cost shift issues before moving forward with a change in structure as such.

Response: The drafting team believes that the proposed standard is the best possible compromise at this time. While there may be a cost shift, this is true under any change that could be considered.

Second, we are concerned about the move to conform back to the NERC time standard of 105 minutes. We contend that the WECC has the option to still be more stringent and only allowing 60 minutes following an event, and we recommend that WECC maintain its current standard of 60 minutes. If the team feels a need to modify the current time window, we recommend that it be aligned with the scheduling windows.

Response: The drafting team has changes the restoration period to conform to the NERC restoration period. The WECC Performance Work Group has review this change and found little risk to the change.

Finally, we believe that proposal standard only partially address the "reserve capacity availability" issue that was so effectively addressed by the ORSTF proposal. One of the key reliability issue faced by the operators today is that the reserves associated with Firm Imports are not available to the operators in case of any outage within the importing Balancing Authority. The ORSTF proposal effectively addressed this issue by requiring procurement of reserves for all imports. In our view, this proposal only partially addresses this issue. We recommend that this proposal be modify to effectively address this issue so provide positive reliability benefits.

Response: The drafting team believes that since the 3 and 3 only will be used in instances where the required level of reserves are greater than the Most Severe Single Contingency, there will be sufficient reserve on both sides of any transaction. Therefore, system reliability will be maintained regardless of where an event occurs.

Thanks for giving us the opportunity to provide these comments. If you have any questions, please contact me at (408) 204-7630.

Ali Amirali
Managing Director - Dynegy Inc.

The BAL-002-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the WECC BAL-002-WECC-1 Standard. This Standard was posted for a public comment period from November 20, 2007 through January 2, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard by posting comments on the WECC website. There were nine sets of comments from nine companies.

In this 'Consideration of Comments' document, stakeholder comments have been organized so that it is easier to see the responses associated with each comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Steve Rueckert at 801-582-0353 or at steve@wecc.biz. In addition, there is a WECC Appeals Process.

Comments and Responses

The proposed contingency reserve requirement of 3% load plus 3% generation penalizes regions with high hydro generation relative to the existing requirement for 5% hydro and 7% thermal. This is contrary to the direction provided by the study group looking into frequency responsive reserves, which concluded that hydro resources are more effective and generally takes on a larger proportionate share in responding to contingencies. Changing the proposed requirement to 3% load plus 2% hydro plus 4% non-hydro would address the issues around what to allocate for resources which are neither hydro nor thermal (wind for example), be more consistent with the existing allocations, and should provide a smoother transition to ultimately adopting some form of frequency responsive reserve requirements.

Allan Woo

Reply: The drafting team believes that having a uniform allocation for reserves based upon load and generation before a frequency responsive reserve standard is implemented is preferred. The FRR standard is expected to measure the response of generators to changes in frequency regardless of generator type. Different generators will respond differently to frequency deviations. In addition, our review of the impact to existing reserve sharing groups and balancing authorities that are not members of reserves sharing groups and the proposed allocation based upon 3% load and 3% generation does not cause a significant shift in reserve allocation from the existing allocation methodology.

The following comment and proposed section relocation request are made on behalf of the Northwest Power Pool Reserve Sharing Group (NWPP RSG). Balancing Authority participants in the NWPP RSG are: AESO, AVA, BCTC, BPAT, CHPD, DOPD, GCPD, IPC, NWMT, PACE,

PACW, PGE, PSE, SMUD, SCL, SPPC, TID, TPWR, and WAUW.

Section D.1.1.4 - Remove Drafting Team comment from the proposed standard. It does not belong in the standard.

Reply: The drafting team comment has been removed.

Section D.1.1.4 - Relocate all of Section D.1.1.4 to Section A.4, Applicability. This Section has more to do with applicability than compliance.

Reply: The drafting team understands the concerns of the NWPP. The drafting team believes the best chance for the standard to receive regulatory approval is to leave the wording from the NWPP in the compliance section.

Don Badley

The Bonneville Power Administration (BPA) would like to thank the BAL-002 Drafting Team for their diligent efforts in developing this standard and for the opportunity to provide comments. BPA supports this current draft of the proposed standard in its entirety. We are especially pleased that the language proposed by the Northwest Power Pool concerning penalty responsibilities of Reserve Sharing Groups was included in this latest draft. This is a particularly important issue for the Northwest. We commend the Drafting Team for addressing it and strongly recommend that the language as written be included in the final standard.

Some parties have asked why this contingency reserve standard is being put forward when work is under way to develop a Frequency Responsive Reserve (FRR) standard by 2009. BPA is well aware of the work being done on the FRR proposal and fully supports it. However, we also understand that the FRR standard is unlikely to be in place in time to meet the FERC-imposed deadline for the Contingency Reserve standard. Furthermore, the FRR standard does not address the non-spinning reserve component of Contingency Reserves. Hence, this updated BAL-002 standard is required in order to properly cover the full range of reserve requirements needed to maintain reliability.

BPA supported a contingency reserve allocation method based on load; however, we do understand the concern that such an allocation approach would cause some amount of cost shifting. BPA believes that the allocation methodology based on 3% of generation within the Balancing Authority plus 3% of the load within the Balancing Authority is an excellent compromise. In addition, a very important and positive feature of the latest draft of BAL-002 is the removal of Load Responsibility from the reserve allocation calculation. The Load Responsibility component of the existing allocation methodology has proven to be difficult to interpret and implement. Its elimination from the standard will alleviate a number of these problems, which the WECC has been attempting to resolve for quite some time.

Reply: Thank you

BPA would like to suggest the following clarifying comments. They are not meant to change the intent of the standard.

1. Modify the language in section R1.1.2 to read "generation minus station service minus net interchange" inside the parentheses and "…three percent of generation minus station service" at the end of the sentence.

Reply: The drafting team made refinements to R1.1.2 to add clarification.

2. Modify section R2.1 to read, "Responds to frequency immediately by governor action."

Reply: The drafting made refinements to R2.1 to incorporate the concept of governor action.

3. Modify section R3.6 to read, "Load, once the Reliability Coordinator has declared a capacity or energy emergency."

Reply: The drafting team implemented this refinement.

4. In section D, we strongly recommend that a reset period of 24 hours be explicitly defined.

Reply: The drafting team believes a reset period of 24 hour is too short and is not appropriate for this standard. Since each Balancing Authority or Reserve sharing Group is required to verify quarterly that operating reserve violations have been reported, the drafting team believes a quarterly reset period is more appropriate.

5. Replace the phrase "Reserve Sharing Group or Balancing Authority" wherever it appears throughout the document with the phrase " Reserve Sharing Group or Balancing Authority (if not part of a Reserve Sharing Group)."

Reply: The drafting team implemented this recommendation as proposed by SMUD.

Thank you again for the opportunity to comment on this document.

John Anasis – BPA Transmission Services
Brenda Anderson – BPA Power Services

The SMUD coordinated response team appreciates the work of the Bal-002 drafting team and supports the standard with one minor modification. For consistency the language in R1, and R2, should R3 state:

"Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group…

Thank you for your hard work in developing a standard that will help alleviate the confusion surrounding the reserves issues.

Robert D Schwermann
On behalf of the SMUD coordinated response team

Reply: The drafting team implemented this recommendation.

PG&E appreciates the work of the Drafting Team and supports the proposed BAL-002-WECC-1 standard. The clarification of Balancing Authority and Reserve Sharing Group responsibilities resulting from the elimination of the Load Responsibility term and the removal of market transactions in calculating reserve requirements are particularly positive changes. Although PG&E recognizes that the 3% gen / 3% load formulation for reserve requirements does not have a technical basis and probably requires reserves in excess of the true technical requirements, it represents a reasonable equitable interim solution to be implemented while FRR requirements are tested and refined. The 3% gen / 3% load compromise also shares reserve requirements equitably across WECC entities of varying ratios of generation to load. In addition, the proposed standard eliminates requirements based on specific generation technologies (hydro vs. thermal), a methodology which did not have a true technical justification and required additional clarification for emerging generation technologies such as wind and solar. In summary, the proposed standard appears to address the most significant flaws with the existing standard while maintaining comparable requirements as an interim bridging solution for WECC entities until FRR requirements can be implemented, which is why PG&E supports this proposed standard.

Kris Buchholz

Reply: Thank you for your comment.

BCTC is appreciative of the hard work by the Standard Drafting Team to develop this draft. We support this standard but have the following comments for the drafting team's further consideration.

1. In R1.2, the language pertaining to interruptible export has been replaced with "Interchange Transaction that the Source BA has claimed as part of its non-spinning contingency reserve." In R3.3, the term "interruptible exports" is identified as an acceptable type of reserve, which must be fully deployable within 10 minutes of notification to meet R1. It would seem a lot clearer if "interruptible export" was also retained in R1.2 unless there is some other type of Interchange Transaction that would require the Sink BA to carry the same amount of additional non-spinning contingency reserve under this Requirement.

Reply: The drafting team made refinements to R1.2, R1.3, and R3.3 to remove reference to interruptible export to clarify the type of transactions in the requirements.

2. In R1.3, the Interchange Transaction claimed by the Sink BA as its Spinning or Non-Spinning Contingency Reserve is meant to capture the existing MORC term for "on-demand obligation" or as described in R3.4, "Reserve held by other entities by agreement." In the WECC MORC, there is a requirement for this type of Interchange Transaction to be scheduled on firm transmission. Did the Standard Drafting Team consider specifying this as a requirement in this standard?

Reply: The drafting team has implemented a refinement to R3.4 to address this issue.

3. We support the comments made by Don Badley that was posted on 07.12.2007.

Reply: Please see response to Don Badley.

Thomas Fung
BCTC, System Operations

We at the Los Angeles Department of Water and Power appreciate the work of the drafting committee on this fundamentally important standard. In order to enhance the standard's value, we suggest the following changes.

1. Add to Section A. 3. (Purpose): "This Standard is not meant to include Regulating Reserves (which are additional to these requirements) or Frequency Responsive Reserves (which will partially or totally replace these requirements)."

Reply: The drafting team believes the purpose statement should address what is covered rather than the items not covered. The comment will be addressed in the reasons why document.

2. Requirements R1.2 and R1.3 place reserve obligations on the Sink and Source Balancing Authorities, respectively, triggered solely by the actions of each other's BA ("…claiming an Interchange Transaction(s) as part of its … Contingency Reserves…"). But what if such "claims" are unjustified (intentionally or not) with respect to the underlying transactions? One solution to this problem would be to amend Section 4.3 (Violation Severity Level for Requirement R3) to read: "… if the Balancing Authority or Reserve Sharing Group used unacceptable resources for Contingency Reserves, including non-qualifying Interchange Transactions."

Reply: The business practice tagging requirements in INT-BPS-009 and INT-BPS-011 identify these transactions specifically; therefore, BA approval of the tags shall ensure that both source and sink BAs agree to the obligations associated with the transactions.

3. Requirement R3.4 shows, as an acceptable form of Contingency Reserves, "Reserve held by other entities by agreement." Let's append to that the phrase "and accessible to the Balancing Authority or Reserve Sharing Group via firm transmission."

Reply: The drafting team has modified R3.4 to address this issue.

As a whole, the proposed standard addresses many of the concerns historically voiced by the industry over the current MORC, and it serves as an interim measure until the Frequency Responsive Reserve Standard goes into effect.

- John Hormozi, L.A. Dept. of Water and Power

Reply: Thank you for your comments.

Chelan PUD supports this draft of the proposed standard.

Chelan understands that WECC is working to implement a Frequency Responsive Reserve standard by 2009 and this new FRR standard may replace some of what is in this proposed BAL-002-WECC-1. Chelan supports the work to implement a FRR standard. However, Chelan feels BAL-002-WECC-1 is still needed at this time because it:

- provides a reasonable compromise between an all load based requirement and an all generation based requirement.
- addresses the non-spinning component of contingency reserve requirement (not addressed by FRR).
- removes "Load Responsibility" from the reserve standard.
- helps meet the FERC imposed deadline to have a permanent reserve standard.
- removes the ambiguity that currently exists regarding the reserve requirement for different kinds of generation.

Chelan notes that the language proposed by the Northwest Power Pool concerning penalty responsibilities of Reserve Sharing Groups is included in this draft. Chelan feels strongly this language remain in the standard, unless resolved in some other manner. Furthermore, Chelan supports the comments of Don Badley that the location of the language should be moved from the compliance section to the applicability section and that the editorial comments of the drafting team be removed.

Reply: Thank you for your comments. Please refer to the response to Don Badley's comments above.

The Alberta Electric System Operator (AESO) appreciates the opportunity to comment and would like to offer the following:

- It is not clear in R3 whether some of the listed type of services can be used to meet the spinning reserve requirement in R2. For example, if spinning reserve is contracted from an external source to the BA area, it should contribute to the meeting of the spinning requirement in R2. And, if an energy or capacity emergency alert has been issued for the BA, then load can be used to meet the CR requirement in R1 as well as the spinning reserve requirement in R2.

Thank you.

Anita Lee, P. Eng.
Manager, Operating Policies and Procedures
Alberta Electric System Operator

Reply: The drafting team believes that any Interruptible Load that has been qualified as spinning reserve would be considered spinning reserve at any time and does not require an emergency alert. The intent of R3.6 is to ensure that Load other than Interruptible Load is utilized as non-spinning reserve only during time of extreme duress. R2 indicates that 50% of R1 must be Spinning Reserve and meet the sub-requirements for Spinning Reserve.

John Jamieson
John.Jamieson@pgn.com

Portland General Electric Merchant is concerned with the movement toward unnecessary changes to the approved standard proposed in BAL-002-WECC-1 particularly due to the motivation being cited. At no time should the basis of a reliability standard be centered on “a compromise” rather than the requirements of operational reliability.

Response: The drafting team’s presentations described the process used to determine the means of calculating the additional reserves that may be necessary, in addition to that determined by MSSC. The team recognizes that the existing standard focuses on only load served by hydro or thermal resources. The team felt compelled to include all types of generation as the Western Interconnection (WI) is experiencing a significant increase in alternative generation sources that are not addressed by the existing standard. The compromise mentioned is the reserve allocation mechanism adopted that recognizes both load and generation responsibilities in providing reserves.

In public meetings held with / by the BAL-002-WECC-1- drafting team there was no evidence presented that illustrated increased reliability under BAL-002-WECC-1. The meetings showed that in fact BAL-002-WECC-1 could result in a reduced level of reliability in the WECC region.

Response: The drafting team disagrees with this statement. In fact, the proposed standard addresses many shortcomings in the existing standard, such as clarifying when an entity needs reserves and what amount. Today’s standard has several ambiguous statements that have caused considerable disagreement and misunderstandings between members. For example the current standard refers to Firm and Interruptible. There are many market products that do not fall in either of those categories, or there is disagreement between BA's/RSG on whether they would fit under Interruptible or Firm. This makes it difficult to be sure a BA is carrying the appropriate quantities. This proposed standard removes the type of market products from the allocation requirements. All of these issues are addressed by the proposed standard.

Why is a reliability entity allowing a compromise on standards that impact reliability?
We are all being held to these standards and they should be defined by what is necessary for reliability, otherwise it isn’t a reliability issue and the market will define the products.

Response: At issue today is that the reliability standard has in the past attempted to define the market products. The WECC has determined that it should not be defining market products in this way. For this reason the drafting team recommends changing the allocation method from what exist today because it includes market products as part of the standard. This in and of itself has caused the uncertainty that exists in the reliability standard, to say nothing of the adverse impacts that are occurring in the WECC markets.

The biggest deficiency of this “compromise” is that it assumes that we have a robust and fully functioning market for reserves. To our knowledge most merchants do not have the right to sell reserves, let alone have extra to sell, and there has not been any formal discussion of how cost based entities can function in a WECC region reserves market. We need to agree that reserves are a reliability issue in determining use and level but a market issue when determining responsibility.

Response: The standard does not assume there is any market for any product. In fact, the standard clearly separates the market issues from the reliability issues. The WECC has created business practices (approved by the OC and MIC) that allow for buying and selling of products that would help a Balancing Authority meet its load service and additional capacity needs. This standard clearly defines how transactions for reserves must be utilized to ensure appropriate information is provided to both source and sink Balancing Authorities. The drafting team disagrees with the statement that reserves are a market issue when determining reliability. Reserves are a reliability issue and should not interfere with markets, and market definitions should not cause confusion within the reliability standards. The products needed to meet the reliability needs will be offered through the markets if there is a demand for them. The drafting team believes that reserves are an issue for the Balancing Authorities as defined in the NERC Functional Model and not an issue for Purchase-Selling Entities.

The public meetings showed the proposed BAL-002-WECC-1 move towards the creation of a market product rather then a reliability standard.

Response: The drafting team disagrees with this statement. The drafting team attempted to address questions it had heard in previous meetings related to how a Balancing Authority would be able to meet its reserve requirements since it would no longer be able to change its reserve responsibility through purchase of energy. The drafting team did not in any way use BAL-002-WECC-1 to create market products. Rather the drafting team ensured that if market products were used to meet an obligation, they were used in an appropriate and correct manner.

WECC has been very clear that the definition of market products is not within their mandate "WECC should focus on the interpretation of reliability criteria. It should not define energy market products." (Load Responsibility July 26, 2007) and it is equally as clear that the proposed BAL-002-WECC-1, while perhaps not intentionally, will result in the definition of a new energy product albeit not named by the standard itself.

Response: The drafting team did not create any new market products. It removed the market products from the reliability standard. Any products discussed at the presentation on February 6th are already in use today. The drafting team strove to ensure that to the extent market products are used to meet a reliability requirement, the rules for doing so are clearly stated.

Is it WECC's intention, with BAL-002-WECC-1, to create an energy product leaving only the naming of said product to the WSPP and other like entities?

Response: Please refer to the response above. To the extent that a product is for a reliability need, such as reserves, the drafting team felt it imperative to define the rules under which this product would be acceptable.

Portland General Electric Merchant encourages the BAL-002-WECC-1 drafting team to work towards the establishment of a standard that is focused on the reliability of the system rather then a compromise that defines a market product.

Response: The drafting team appreciates this advice and feels that is exactly what was done.

Portland General Electric Merchant

Mike Goodenough
Mike.Goodenough@powerex.com

The proposed standard BAL-002 is seriously flawed in that it is not based on a technical evaluation of reserves from a reliability standpoint. The team that developed the standard has indicated that the 3% load, 3% generation numbers were proposed as a compromise. Though there may be some benefits to moving the reserves requirement towards load, it cannot be done without an in-depth study to determine the reliability impacts, market impacts, and the costs to the Balancing Authorities, particularily the costs that will be shifted to the BAs that are primarily load. None of this analysis has been done.

Response: The drafting team disagrees with the statements made here. First, the drafting team agreed to a compromise in the allocation methodology, not in the amount of reserves held in the WECC. In other words, the drafting team discussed basing the reserves on Generation only, Load only or a compromise position of half and half. The compromise position was determined to be the best solution because it minimized adverse impacts to the different entities that are currently applicable entities (Reserve Sharing Groups (RSGs) or the stand-alone Balancing Authorities) under the existing WECC standard. The reliability impacts were reviewed by looking at the amount of reserves for each applicable entity in the WECC. This review clearly shows that there is no significant cost increase to any of the applicable entities in the WECC. Based on the changes to each entity, it is the drafting team's belief that there should not be any significant changes to costs to the overall Reserve Sharing Groups (RSGs) or the stand-alone Balancing Authorities. If a RSG decides to change its allocation methodology at this time, there could be significant impacts to members of that RSG. However, the drafting team ensured that the WECC standard does not require a RSG to reallocate its reserve requirement. The allocation methodology has been left up to the members of that RSG.

The Frequency Response Reserves Project is a far more technically sound approach to re-examining the way reserve requirements should be calculated. Given that the existing reserve requirement standard has a proven reliability track record, we feel it should remain in place until the FRR project has been concluded. BAL-002 at best is change for the sake of change, but at worst it is potentially a serious step backward in reliability for the western region.

Response: The Frequency Response Reserve Project is not ready for the WECC to adopt as a standard at this time. It will be some time before it is ready. In the meantime, issues were raised with the existing standard during the FERC approval process that FERC required to be addressed within a very limited timeframe. The drafting team believes it has addressed the issues in a manner that can be adopted here without causing delay to a more technically based standard. It is possible, but not assured by any means that this standard may be revised during the FRR development process. An FRR standard would ensure that the Western Interconnection carries sufficient reserves to respond to frequency declination. However, adoption of an FRR standard will not erase the need for contingency reserves. The drafting team proposes this standard as a long term solution to contingency reserve issues that should dovetail with an FRR standard. Until then, the WECC needs a clear, unambiguous contingency reserve standard for both compliance and reliability.

Joe Hoerner
joseph.hoerner@pse.com

Puget Sound Energy (PSE) appreciates the opportunity to provide comments on the proposed WECC Standard BAL-002-WECC-1 (Contingency Reserve). These comments are provided on behalf of Puget Sound Energy's transmission and merchant functions.

Upon review and analysis of the proposed Standard BAL-002-WECC-1, PSE can not determine how this standard provides any additional reliability over today's standard. The proposal alters the calculation for contingency reserves instead of clearly defining how contingency reserves would be activated to ensure system reliability. Furthermore, PSE's analysis indicates that adoption of this standard will result in significant cost shifts from generators to load-serving entities. PSE's ratepayers could expect to pay an additional $14,000,000 more per year in increased contingency reserve obligations without any added reliability benefit. PSE cannot find any legitimate reason as to why our regulating entities could justify our approval of such a cost increase with no benefit. If, in fact, the primary justification for creating the standard is to firmly establish the obligation of where the reserve obligation lies, then we feel it is more appropriate to address this issue in the commercial forum.

Response: Based on discussions with PSE, the drafting team believes that the methodology used to determine the impact to PSE is a reasonable methodology and, therefore, the results are a possible outcome. The standard does not dictate how a Reserve Sharing Group allocates the reserve requirement to its members. The drafting team recommends that all entities in a Reserve Sharing Group work with the RSG to insure equal allocation of savings due to reallocation of reserve obligation. The drafting team disagrees that the commercial forum is the correct venue to establish where the reserve obligation lies, this is a reliability issue. However, the commercial forum can be used to determine how an entity meets its obligation.

Finally, the drafting team was not asked to clarify when reserves should be activated or how they should be activated. The drafting team only identified the need to determine the level of reserves needed as being within its scope. The drafting team believes the NERC standard addresses when reserves should be activated. Each individual entity determines how reserves are activated. The selection of which reserve to activate should not be dictated by a standard.

Anonymous

The proposed standard is silent on how Firm Contingent generation reserve requirements (which would be 3%) would be the requirement of the sink rather than the source. It is unacceptable to require IPPs to purchase the 3% reserves from the host BA and it is also unacceptable to require IPPs to purchase firm transmission and capacity in order to provide reserves for their transactions. New reserve requirements must allow the reserve requirement to be exported to the sink when the unit is sold firm contingent. The sink BA must also be aware of the fact that they have this responsibility. This responsibility can be shifted, and must be clear to all parties to the transaction.

Response: The drafting team disagrees with this statement. The responsibility for providing reserves resides with BAs and RSGs not IPPs. The standard does not dictate how a Reserve Sharing Group or Balancing Authority allocates its reserve requirement. With the proposed standard, reserve obligation is no longer dictated by transaction type. This is one of the driving forces behind the creation of this standard. The issues raised by Anonymous should be settled in the commercial forum because there is no requirement in the standard for an IPP to carry reserves. If the IPP has a reserve allocation from its RSG or BA, then an IPP may purchase reserve from its host BA or it may purchase reserve from the sink BA. Under the proposed standard, the responsibility is split between the two Balancing Authorities. The need to activate reserves would reside with the sink Balancing Authority if the unit were to be unable to generate suddenly since the schedule would likely be curtailed when the unit tripped.

Drafting Team for BAL-STD-002

FIRST NAME	LAST NAME	COMPANY
Jeffrey	Ackerman	Western Area Power Administration (WAUC) (Marketing)
Ali	Amirali	Dynegy, Inc.
John	Anasis	Bonneville Power Administration (Transmission - Primary)
Brenda	Anderson	Bonneville Power Administration (Marketing)
David	Frederick	Salt River Project
Steve	Heidt	Alberta Electric System Operator
Duane	Helderlein	TriState Generation & Transmission Association, Inc. (TSMD)
Robert	Johnson	Public Service Company of Colorado (RMRG Representative)
Steve W.	Johnson	Western Area Power Administration (Transmission)
Kenneth	Wilson	Western Electricity Coordinating Council
David	Lemmons	Public Service Company of Colorado
Clyde	Loutan	California Independent System Operator (Alternate)
John	Marusenko	British Columbia Transmission Corporation
Bart	McManus	Bonneville Power Administration (Transmission - Alternate)
Joe	Medina	Arizona Public Service Company
Tim	Newton	Non-Affiliated Directors (Board Representative)
Philip	Tice	Deseret Generation and Transmission Cooperative
John	Tolo	Tucson Electric Power Company
Gregory	Van Pelt	California Independent System Operator (Primary)
Vickie	VanZandt	Bonneville Power Administration (Board Representative)
Ben	Williams	Pacific Gas and Electric Company

SP — State and Provincial
TP — Transmission Provider
TC — Transmission Customer
IS - Interested Stakeholder

OPERATING COMMITTEE

BAL-002-WECC-1

Name of Organization	Name of Voting Member	Voting Class	YES	NO	Abstain
Alberta Electric System Operator (AESO)	Doug Hincks	TP			X
AltaLink L.P. (ALTA)	Rick Spyker	TP			X
Aquila Networks-WPC (WPE)	Al Logan	TC	X		
Arizona Public Service (AZPS)	Mark Hackney (alternate)	TP	X		
Arizona Public Service (AZPS)	David Hansen	TC	X		
ATCO Electric Ltd. (ATCO)	Blaine Beisiegel	TP		X	
Avista Corp	Scott J. Kinney (alternate)	TP			X
Basin Electric Power Cooperative (BEPC)	Becky Kern	TC	X		
Bear Energy LP (BEAR)	Jeff Winkler (alternate)	TC			X
Black Hills Power and Light Company (BHPL)	Pam Pahls	TP	X		
Bonneville Power Administration-Power Bus Line (BPAP)	Fran Halpin	TC	X		
Bonneville Power Administration-TBL (BPAT)	Don Watkins	TP	X		
BP Energy Company	Julie Martin	TC	X		
British Columbia Hydro and Power Authority (BCHA)	Clement Ma	TC		X	
British Columbia Transmission Corporation (BCTC)	Devinder Ghangass	TP	X		
California Department of Water Resources (CDWR)	Glenn Solbert	TC	X		
California Energy Commission (CEC)	Bill Chamberlain (alternate)	SP	X		
California ISO (CISO)	James McIntosh	TP	X		
California Mexico Reliability Center	Greg Tillitson — TC	IS	X		
Calpine Corporation (CALP)	Frank Obertance	TC	X		
Colorado Springs Utilities (CSU)	Steve Schaarschmidt	TP	X		
Constellation Energy Commodities Group, Inc. (CCG)	Mary Lynch	TC	X		
Coral Power LLC	Michael Wong	TC	X		
Deseret Generation & Transmission Co-op (DGT)	Phil Tice	TC	X		
Deseret Generation & Transmission Co-op (DGT)	L'Dee Curtis	TP	X		
Dynegy, Inc. (DYN)	Brian Theaker	TC	X		
El Paso Electric Company (EPE)	Jose Nevarez	TP	X		
Eugene Water & Electric Board (EWEB)	Dean Ahlsten	TC	X		
Fortis Energy Marketing & Trading Group (FEMT)	Jay Alexander	TC		X	
FPL Energy LLC (FPLE)	Mark J. Smith	TC	X		
Gila River Power, L.P. (PGR)	Kenneth Parker	TC			X
Great Basin Transmission, LLC (GBT)	Ali Amirali	TC			X
Highland Energy LLC	Bryan Bradshow	IS	X		
Idaho Power Company (IPC)	Tessia Park	TP	X		
Metropolitan Water District of Southern California (MWD)	Garry Chinn	TP			X
Mirant Americas, Inc. (MIR)	John Stout	TC	X		
Modesto Irrigation District (MID)	Toxie Burriss	TP		X	

Board of Directors
April 16–18, 2008 **Voting Summary**
Coronado, CA **BAL-002-WECC-1**

Last Name	First Name	Organization	Class
Anderson	Bob	Non-affiliated Director	Non-Affiliated
Areghini	David	Salt River Project	Class 1
Barbash	Carolyn	Sierra Pacific Power Company	Class 1
Beyer	Lee	California Public Utilities Commission	Class 5
Brown	Duncan	Calpine Corporation	Class 3
Campbell	Ric	Utah Public Service Commission	Class 5
Cauchois	Scott	CADRA	Class 4
Chamberlain	Bill	California Energy Commission	Class 5
Cleary	Anne	Mirant Americas, Inc.	Class 3
Conway	Teresa	Powerex Corp.	Class 6
Coughlin	John	Non-affiliated Board Member	Non-Affiliated
Dearing	Bill	Grant County PUD	Class 2
Ferreira	Richard	TANC Executive Advisor	Class 2
Grantham-Richards	Maude	Farmington Electric Utility System	Class 2
Gutting	Scott	Energy Strategies, LLC	Class 4
Kelly	Nancy	Utah Committee of Consumer Services	Class 4
King	Jack	Non-affiliated Board Member	Non-Affiliated
LaFond	Steve	The Boeing Company	Class 4
*Little	Doug	British Columbia Transmission Corporation	Class 6
McMaster	Dale	Alberta Electrical System Operator	Class 6
Moya	Jesus	Comision Federal de Electricidad	Mexico
Newton	Tim	Non-affiliated Director	Non-Affiliated
Sharpless	Jananne	Non Affiliated Board Member	Non-Affiliated
Smith	Marsha	Idaho Public Utilities Commission	Class 5
Stout	John	Mariner Consulting	Class 3
Tarplee	Gary	Southern California Edison	Class 1
Thuston	Tim	Williams Power	Class 3
Weis	Larry	Turlock Irrigation District	Class 2
VanZandt	Vicki	Bonneville Power Administration	Class 1
Zaozirny	Lori Ann	British Columbia Utilities Commission	Class 6

The Board Members listed above voted whether to approve BAL-002-WECC-1.
Twenty-eight members voted Yes.
One member (identified with an asterisk) voted No.
Two members (not identified) abstained.

WECC Standard BAL-002-WECC-1 — Contingency Reserves

WECC has been attempting to clarify ambiguities related to the Contingency Reserve requirements that exist in today's Standard for more than 5 years. The lack of agreement among entities about the correct interpretation of the Standard has thwarted previous attempts. Unresolved issues include ambiguity in the definition of load responsibility, inclusion of market transactions in the determination of reserve requirements, and the emergence of market products that do not fit into the reliability concept. By modifying the manner in which required reserves are determined, the drafting team has endeavored to remove these controversial issues without significantly altering the amount of reserves required in the WECC.

The drafting team used information for eight selected hours from a one year period for the entities — Reserve Sharing Groups and Balancing Authorities not members of Reserve Sharing Groups — responsible for reserves in the WECC. Using this information, the drafting team estimated the impact of different levels of reserve requirements. Based on our review and discussions, the drafting team is proposing an allocation of reserves based on a combination of generation and load, an approach intended to minimize adverse impacts to any one entity while separating the market products and reliability requirements. Reserve requirements, as proposed, will be will be the greater of (i) three percent (3%) times the Balancing Authority (BA) Load plus three percent (3%) times the BA net generation, or (ii) an entity's Most Severe Single Contingency. Additionally, the requirement to maintain at least half of this total as spinning reserve remains. The estimated impact of these changes to the required level of reserves in the WECC is a reduction of 650 MWs or less, a decrease of approximately 9% at most. Of the eight representative hours of data, only in one of these hours would any entity have seen a minimal increase in its reserve requirement. Additionally, the proposed allocation of reserves results in very little change in the distribution of reserves in the WECC. Note that these numbers only reflect the aggregate requirement for Reserve Sharing Groups and that the impact to individual members of the groups cannot be determined.

The proposed standard accomplishes the following objectives:

- It clearly identifies the responsible entity and creates a measurable requirement by imposing a Contingency Reserve Requirement based upon a BA's generation (3%) and load (3%).
- It maintains WECC Contingency Reserves similar to today's levels (if not higher, since it is currently unknown whether reserves are being held for some transactions). Based on information provided to the drafting team, the proposed requirements would cause an overall decrease of WECC required reserves of approximately 350 MWs (from approximately 10,850 MWs to 10,500 MWs) on

high load days. The largest change of required contingency reserves during the hours reviewed indicate a decrease of 650 MW.

- By not carrying all Contingency Reserves based on load or all based on generation, it minimizes overall cost shifting and shares the requirement between generation and load.
- It eliminates ambiguity related to transactions by eliminating their impact on the determination of requirements (with the exception of Contingency Reserve-specific Transactions). It eliminates the need for WECC to define products that are bought and sold between marketing entities, which is important because the responsible BA is not privy to the specifics surrounding each transaction. Each BA will clearly understand the requirement without having to monitor each transaction and determine the impact of each tag to its requirements.
- It removes the uncertainty of whether or not the requirements change based on the type of transmission being used to move energy from one BA to another.
- It helps WECC to better transition to a Frequency Responsive Reserve (FRR) Standard that would not include transactions (with the exception of FRR-specific transactions).
- It eliminates the need to define and agree on the requirements for non-hydro and non-thermal generation. Different regions currently seem to use differing reserve requirements for generation such as wind.
- It retains the NERC standard of Most Severe Single Contingency (MSSC) as the minimum level of Contingency Reserves, as the requirement would become the greater of MSSC or 3 % of net generation plus 3% of load.
- It maintains applicability to BA or Reserve Sharing Group, the same as today.
- It enhances the ability to meet load due to any type of contingency by carrying for both generation and load, because Contingency Reserves may be activated for loss of a transaction due to transmission or generation loss.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

Action: IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief — **Remand**

Summary Conclusion and Recommendation:

- NERC recommends IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief be remanded as it is no longer more stringent than to the NERC Reliability Standard.
- The proposed standard IRO-006-WECC-1 is proposed on the basis that it is more stringent than existing NERC Reliability Standards and is necessary as the only source of a mandatory process for mitigating overloads due to unscheduled flows in the Western Interconnection. While WECC made very useful conforming changes to the existing FERC-approved standard, WECC-IRO-STD-006-0, that clarify the applicable entities and eliminate the inclusion of entities (for example Load Serving Entities) that may not have the ability to ensure mitigation of overloads as specified in the FERC and NERC directives, the replacement standard no longer presents a comprehensive approach for mitigation of transmission overloads due to unscheduled flows.
- Although WECC adequately addressed the NERC and FERC directives, the additional changes made are problematic. As a result of these changes, the proposed Regional Reliability Standard no longer references WECC's Unscheduled Flow Mitigation Plan that contains directions to reduce flows that include the use of phase-angle-regulators, series capacitors, and back-to-back DC lines before transaction curtailment. These aspects originally made the current approved version of the standard more stringent than the NERC Reliability Standard. This is no longer the case.
- Furthermore, the proposed Regional Reliability Standard is inconsistent with the standard's purpose, "to mitigate transmission overloads due to unscheduled flow" and the corresponding continent-wide NERC Reliability Standard that currently references the entire WECC unscheduled flow mitigation plan as it eliminates the requirements to implement coordinated action per steps 1–3 in the plan.
- The remaining requirements, R1 that requires Reliability Coordinators to respond to a Transmission Operator's request for relief within five minutes and R2 that requires that Balancing Authorities implement the request to provide relief, should be included as a Regional Variance to the NERC Reliability Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief. These requirements propose alternate activities to that of the continent-wide requirements and support the reliability objective of the standard. This is in alignment with the NERC definition of a Regional Variance as stated in Section 202 of the Rules of Procedure[1].

[1] Variance means an aspect or element of a reliability standard that applies only within a particular regional entity or group of regional entities, or to a particular entity or class of entities. A variance allows an alternative approach to meeting the same reliability objective as the reliability standard, and is typically necessitated by a physical difference. A variance is embodied within a reliability standard and as such, if adopted by NERC and approved by the ERO governmental authority, shall be enforced within the applicable regional entity or regional entities pursuant to delegated authority.

Background*:* FERC-approved Regional Reliability Standard WECC-IRO-STD-006-0 — Qualified Path Unscheduled Flow Relief on the basis that it was more stringent than the existing NERC Reliability Standard IRO-006-3 — Reliability Coordination — Transmission Loading Relief. Specifically, WECC-IRO-STD-006-0 — Qualified Path Unscheduled Flow Relief references WECC's Unscheduled Flow Mitigation Plan that contains directions to reduce flows that include use of phase-angle-regulators, series capacitors, and back-to-back DC lines before transaction curtailment. These aspects originally make the current approved version of the standard more stringent than the NERC Reliability Standard. Further, WECC explained that WECC-IRO-STD-006-0 is essential because it is the only source of a mandatory process for mitigating overloads due to unscheduled line flows in the Western Interconnection.[2]

In its June 8, 2007 Order approving eight WECC Regional Reliability Standards that included WECC-IRO-STD-006-0, FERC directed WECC to make conforming changes to the standard based on the shortcomings identified in NERC's evaluation of the standard and on its own motion, as follows:

1. Remove the sanctions table that is inconsistent with the NERC Sanction Guidelines and add Violation Risk Factors and Violation Severity Levels;
2. Clarify the term "receiver" and the applicability of the standard;
3. Consider industry comments that LSE's may not be able to meet the requirements of the Regional Reliability Standard (WECC-IRO-STD-006-0);
4. Conform the standard to the NERC Reliability Standards, specifically the effective date, that should conform to language stating it should become effective on the first day of the following quarter upon regulatory approval; and
5. Align the definitions with NERC definitions.

Further, FERC supported NERC's conditions for approval that WECC meet its commitment to address the shortcomings over the course of the year.

Proposal IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief: The proposed Regional Reliability Standard, IRO-006-WECC-1 was submitted to NERC on June 11, 2008 for approval, replacing the FERC-approved WECC-IRO-STD-006-0. In processing the proposed Regional Reliability Standard, WECC indicated it used its standards development procedure that existed at the time per its Regional Delegation Agreement with NERC.

The current standard, WECC-IRO-STD-006-0, identifies when an operator shall request curtailments, states that responsible entities shall comply with the request for curtailments in a timely manner, and establishes the procedures for reducing flows. The revised standard, IRO-006-WECC-1, identifies the responsible entity for initiating schedule curtailments and the responsibility for implementing the curtailments. The revised standard no longer establishes when an operator shall request curtailments and does not establish the procedures for reducing flows.

In the proposed IRO-006-WECC-1, WECC implemented the FERC and NERC directives associated with the Order approving WECC-IRO-STD-006-0. The proposed replacement standard, IRO-006-WECC-1, was modified such that it no longer contains the sanctions table; includes

[2] Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007) pg 22.

Violation Severity Levels, Violation Risk Factors, Measures, and Time Horizons; conforms the effective date format to that of the NERC Reliability Standards; conforms the overall format of the standard to that of the NERC Reliability Standards; eliminates the proposed terms that conflicted with the NERC Glossary of Terms; removes the use of the term "receiver"; modifies the applicability of the standard to include Balancing Authorities and Reliability Coordinators; and removes LSEs as a responsible entity. WECC also modified the standard numbering to conform to the NERC Reliability Standards numbering convention.

While WECC made the directed conforming changes, WECC also significantly modified the original WECC-IRO-STD-006-0 in the proposed version 1 standard. Most significantly, WECC modified the standard such that it only includes the curtailment portion of the Unscheduled Flow Mitigation Plan. IRO-006-WECC-1, R1 specifies that the responsibility for implementing curtailments is assigned to the Reliability Coordinators and IRO-006-WECC-1 R2 specifies that the responsibility for implementing the curtailments is assigned to Balancing Authorities. WECC eliminated the obligation for when a Transmission Operator shall request curtailments and eliminated the procedures for reducing flows.

NERC 45-Day Posting: In June 11, 2008 WECC submitted the seven Tier 1 replacement standards for NERC evaluation. NERC posted the seven proposed Regional Reliability Standards for a 45-day public posting beginning April 4–May 20, 2008. The proposed Regional Reliability Standard IRO-006-WECC-1 received no substantive comments during the NERC posting.

NERC Evaluation: In accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*, approved by the Regional Reliability Standards Working Group, NERC provided its evaluation of the proposed IRO-006-WECC-1 standard to WECC on July 30, 2008 (Appendix 4). In this report NERC made several recommendations to the proposed IRO-006-WECC-1 standard to which WECC responded in an August 18, 2008 letter (Appendix 5):

- The proposed standard no longer contains requirements that are more stringent than the continent-wide NERC Reliability Standard IRO-006-4 — Reliability Coordination — Transmission Loading Relief. This was the basis of justification for the Regional Reliability Standard and is the basis for the existing request for approval for IRO-006-WECC-1. By eliminating the technical requirements that specify when an operator is to request a curtailment, and the procedure for mitigating the overload, the standard no longer meets FERC criteria for a approving a Regional Reliability Standard specified in Order No. 672: A regional difference from a continent-wide NERC Reliability Standard must be more stringent than the continent-wide NERC Reliability Standard.

WECC argues the proposed standard should improve the efficiency of the program including improved compliance, more certain unscheduled flow relief, and fewer complications associated with multiple entities taking partial responsibility for curtailment activity. Further, WECC replied it is not necessary to reference the remainder of the Unscheduled Flow Mitigation Plan because the remaining items contain procedural requirements explaining "how," not "what." The proposed IRO-006-WECC-1 standard includes requirements to reduce schedules, which then require adjustments to generation patterns. This prevents potential overloads during the next operating hour. Importantly, the requirements for mitigation of an actual (real-time) overload are contained in TOP-007-WECC-1 — System Operating Limits.

- The proposed standard includes a defined term for Transfer Distribution Factor (TDF) that conflicts with the NERC-defined term in the NERC Glossary of Terms. WECC acknowledged this inconsistency in the response to NERC's comments.
- While the proposed standard contains clear Violation Severity Levels these compliance elements should be in a consistent format with the continent-wide standards.

Supporting Documents:

- Appendix 1 — Regional Reliability Standard Submittal Request
- Appendix 2 — Standard Development Roadmap
- Appendix 3 — Consideration of Comments document on NERC's posting of the regional standard
- Appendix 4 — NERC Evaluation of WECC Regional Standards
- Appendix 5 — WECC Response to NERC Evaluation
- Appendix 6 — WECC Response to FERC Comments
- Appendix 7 — WECC Consideration of Comment Reports
- Appendix 8 — WECC Standards Drafting Team
- Appendix 9 — WECC Balloting
- Appendix 10 — WECC Standard Drafting Team White Paper

To page 1 resource links

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Regional Reliability Standard Submittal Request

Region: Western Electricity Coordinating Council

Regional Standard Number: IRO-006-WECC-1

Regional Standard Title: Qualified Transfer Path Unscheduled Flow (USF) Relief

Date Submitted: June 10, 2008

Regional Contact Name: Steven L. Rueckert

Regional Contact Title: Director of Standards

Regional Contact Telephone Number: (801) 582-0353

Request (check all that apply):

☒ Approval of a new standard
☐ Revision of an existing standard
☒ Withdrawal of an existing standard
☐ Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

☒ Yes April 16, 2008
☐ No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:

The purpose of this standard is to create a permanent replacement standard for IRO-STD-006-0. IRO-006-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when IRO-STD-006-0 was approved as a NERC reliability standard.

To page 1 resource links

Concise statement of the justification of the request:

The proposed IRO-006-WECC-1 Regional Reliability Standard contains unscheduled flow curtailment requirements for the Western Interconnection that are currently cover in IRO-STD-006-0. The NERC standard IRO-006-4 contains requirements transmission loading relief requirements for the Eastern Interconnection and only references the WECC Regional Reliability Standard IRO-STD-006-0, which contains the transmission loading relief requirements for the Western Interconnection.

The WECC Regional Reliability Standard IRO-STD-006-0 and Qualified Path Unscheduled Flow Relief responsibilities do not conform to the current NERC functional model. The WECC Regional Reliability Standard IRO-STD-006-0 standard assigns Load Serving Entities (LSEs) the responsibility of curtailing schedules to reduce unscheduled flow, a reliability function that the NERC functional model now assigns to Reliability Coordinators and Balancing Authorities. In the functional model, NERC holds that LSEs should not be assigned responsibility for reliability. Therefore, the assignment of reliability functions to LSEs is not compatible with the NERC functional model or NERC Standard IRO-006. Additionally, the existing IRO-STD-006 standard places the sole responsibility for providing relief upon the LSE without providing the ability for the LSE to ensure compliance (e.g. the Balancing Authority does not have to approve a curtailment request made by the LSE).

In the proposed IRO-006-WECC-1 standard, responsibility for initiating schedule curtailment is assigned to the Reliability Coordinators, and the responsibility for implementing the curtailments is assigned to Balancing Authorities. The proposed standard improves the efficiency of the program including improved compliance, more certain unscheduled flow relief, and fewer complications associated with multiple entities taking partial responsibility for curtailment activity.

Other — please attach or include as separate files:

- The text of the Regional Reliability Standard in MS Word format that:
  - has either been, or is anticipated to be, approved by the regional entity's board, and
  - is in a format consistent with the NERC template for reliability standards.
- An implementation plan.
- The regional entity standard drafting team roster.
- The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.
- The final ballot results, including a list of significant minority issues that were not resolved, and
- For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

Completed Actions	Completion Date
1. Post Draft Standard for initial industry comments	September 21, 2007
2. Drafting Team to review and respond to initial industry comments	November 30, 2007
3. Post Draft Standard for industry comments	November 30, 2007
4. Drafting Team to review and respond to industry comments	January 17, 2008
5. Post Draft Standard for Operating Committee approval	January 17, 2008
6. Operating Committee approved proposed standard	March 6, 2008
7. Post Draft Standard for WECC Board approval	March 12, 2008
8. Post Draft Standard for NERC comment period	April 14, 2008
9. WECC Board approved proposed standard	April 16, 2008
10. NERC comment period ends	May 20, 2008
11. Drafting Team to review and respond to industry comments	May 31, 2008

Description of Current Draft:

The purpose of this standard is to create a permanent replacement standard for IRO-STD-006-0. IRO-006-WECC-1 is designed to implement the directives of FERC and recommendations of NERC when IRO-STD-006-0 was approved as a NERC reliability standard.

This version of the IRO-006-WECC-1 standard is for NERC Board of Trustee ballot. The WECC Board of Directors approved the standard April 16, 2008. WECC Operating Committee approved the standard March 6, 2008. The WECC Board of Directors and Operating Committee request that the NERC Board of Trustees approve the IRO-006-WECC-1 Standard as a permanent replacement standard for IRO-STD-006-0 and that the NERC Board of Trustees submits the standard to FERC for approval and replacement of IRO-STD-006-0.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. NERC Board approval request	June 2008
2. Request FERC approval	June 2008

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these definitions will be removed from the standard and added to the Glossary.

DEFINITIONS:

Contributing Schedule is defined as a Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.

Qualified Transfer Path: A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.

Qualified Controllable Device: A controllable device installed in the Interconnection for controlling energy flow, and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.

Qualified Transfer Path Curtailment Event: Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (see Attachment 1-IRO-006-WECC-1) during which the curtailment tool is functional.

Transfer Distribution Factor (TDF): The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WE**CC** IRO-006-WECC-1).]

Relief Requirement: The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WE**CC** IRO-006-WECC-1.

A. Introduction

1. **Title:** **Qualified Transfer Path Unscheduled Flow (USF) Relief**

2. **Number:** IRO-006-WECC-1

3. **Purpose:** Mitigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths.

4. **Applicability**

   4.1. Balancing Authorities

   4.2 Reliability Coordinators

5. **Effective Date:** The first day of the first quarter after applicable regulatory approvals.

B. Requirements

R.1. Upon receiving a request of Step 4 or greater (see Attachment 1-IRO-006-WECC-1) from the Transmission Operator of a Qualified Transfer Path, the Reliability Coordinator shall approve (actively or passively) or deny that request within five minutes. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R.2. The Balancing Authorities shall approve curtailment requests to the schedules as submitted, implement alternative actions, or a combination there of that collectively meets the Relief Requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Reliability Coordinator shall have evidence that it approved or denied the request within five minutes in accordance with R1.

M2. The Balancing Authorities shall have evidence that they provided the Relief Requirement through Contributing Schedules curtailments, alternative actions, or a combination that collectively meets the Relief Requirement as directed in R.2.

D. Compliance

1. **Compliance Monitoring Process**

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2. Compliance Monitoring Period and Reset

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reviews conducted monthly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 Compliance Monitoring Period: A Qualified Transfer Path Curtailment Event

1.2.2 The Performance-reset Period is one calendar month.

1.3. Data Retention

Reliability Coordinators and Balancing Authorities shall keep evidence for Measure M.1 through M2 for three years plus current, or since the last audit, whichever is longer.

1.4. Additional Compliance Information

Compliance shall be determined by a single event, per path, per calendar month (at a minimum) provided at least one event occurs in that month.

2. Violation Severity Levels of Non-Compliance for Requirement R1

2.1. **Lower:** There shall be a Lower Level of non-compliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a Step 4 or greater request greater than five minutes after receipt of notification from the Transmission Operator of a Qualified Transfer Path.

2.2. **Moderate:** Not Applicable

2.3. **High:** Not Applicable

2.4. **Severe:** Not Applicable

3. Violation Severity Levels of Non-Compliance for Requirement R2

3.1. **Lower:** There shall be a Lower Level of non-compliance if there is less than 100% Relief Requirement provided but greater than or equal to 90% Relief Requirement provided or the Relief Requirement was less than 5 MW and was not provided.

3.2. **Moderate:** There shall be a Moderate Level of non-compliance if there is less than 90% Relief Requirement provided but greater than or equal to 75% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.

3.3. **High:** There shall be a High Level of non-compliance if there is less than 75% Relief Requirement provided but greater than or equal to 60% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.

3.4. **Severe:** There shall be a Severe Level of non-compliance if there is less than 60% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	

Attachment 1 WECC IRO-006-WECC-1
WECC UNSCHEDULED FLOW MITIGATION
SUMMARY OF ACTIONS

Step	**Action Description**	Unscheduled Flow Accommodation across Path	**Equivalent Percent Curtailment Required in Contributing Schedule -Based on amount of Unscheduled Flow across the Qualified Transfer Path** (Transfer Distribution Factor)				
			10-14%	**15-19%**	**20-29%**	**30-49%**	**50+ %**
1	Operate controllable devices in path	NA					
2	Accommodation	50 MW or 5% of maximum transfer limit					
3	Coordinated operation of Qualified Controllable Devices	50 MW or /5% of maximum transfer limit					
4	First level curtailment	50 MW or 5% of maximum transfer limit				10%	20%
5	Second level curtailment	50 MW or 5% of maximum transfer limit			10%	15%	25%
6	Accommodation	75 MW or 6% of maximum transfer limit			10%	15%	25%
7	Third level curtailment	75 MW or 6% of maximum transfer limit		10%	15%	20%	30%
8	Accommodation	100 MW or 7% of maximum transfer limit		10%	15%	20%	30%
9	Fourth level curtailment	100 MW or 7% of maximum transfer limit	10%	15%	20%	25%	35%

Appendix 3

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Report Form for WECC Standard IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow Relief

The IRO-006-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the IRO-006-WECC-1 Standard. This Standard was posted for a 45-day public comment period from April 4, 2008 through May 20, 2008. NERC distributed the notice for this posting on April 7, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were two sets of comments from four companies representing four of the ten Industry Segments as shown in the table on the following pages.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the Standard can be viewed in their original format at:

http://www.nerc.com/~filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Manager of Regional Standards, Stephanie Monzon at Stephanie.monzon@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[3]

[3] The appeals process is described in the NERC Regional Reliability Standards Development Procedure: ftp://www.nerc.com/pub/sys/all_updl/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Chuck Westbrook	Bonneville Power	✓		✓		✓	✓				
2.	Annette Bannon	PPL Generation, LLC					✓	✓				
3.	Jon Williamson	PPL EnergyPlus						✓				
4.	John Cummings	PPL EnergyPlus						✓				
5.	Tom Olson	PPL Montana, LLC					✓					

Index to Questions, Comments, and Responses

1. **Was the WECC Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief developed in a fair and open process, using the Process for Developing and Approving WECC Standards?**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook	X		
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson	X		PPL supports this much needed update to the unscheduled flow standard.
Response: Thank you for your support.			

2. **Does the WECC Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief pose an adverse impact to reliability or commerce in a neighboring region or interconnection?**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

3. **Does the WECC Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief pose a serious and substantial threat to public health, safety, welfare, or national security?**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

4. Does the WECC Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook		X	
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

5. Does the WECC Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief meet at least one of the following criteria?

- **The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard**
- **The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard**
- **The proposed regional difference is necessitated by a physical difference in the bulk power system.**

Summary Consideration:

Commenter	Yes	No	Comment
Chuck Westbrook	X		
Response: Thank you.			
Annette Bannon, Jon Williamson, John Cummings, and Tom Olson			
Response:			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Evaluation of Western Electricity Coordinating Council (WECC) Regional Standards

Executive Summary
July 30, 2008

On June 11, 2007, the WECC submitted the following seven regional standards for NERC evaluation to replace eight original WECC regional standards approved by NERC and FERC in 2007:

- BAL-002-WECC-1 — Contingency Reserves,
- FAC-501-WECC-1 — Transmission Maintenance,
- IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief,
- PRC-004-WECC-1— Protection System and Remedial Action Scheme Misoperation,
- TOP-007-WECC-1 — System Operating Limits,
- VAR-002-WECC-1 — Automatic Voltage Regulators and
- VAR-501-WECC-1 — Power System Stabilizer

NERC posted these seven proposed regional standards for a 45-day public posting beginning April 4–May 20, 2008. The standards received several comments during the NERC public posting. WECC supplied NERC with its responses to the comments on June 11, 2008. WECC did not make conforming changes to the standards as a result of the comments received during the NERC posting. WECC submitted these standards for NERC evaluation on June 11, 2008.

In accordance with NERC's *Rules of Procedure* and the *Regional Reliability Standards Evaluation Procedure* approved by the Regional Reliability Standards Working Group, NERC performed a review of the WECC proposed standards. The intent of this document is to provide WECC with NERC's feedback regarding their regional standards.

In this review, NERC presents a summary of observations for each proposed WECC regional standard. In Appendix A, NERC includes a redlined copy of each proposed regional standard with detailed comments included. NERC believes WECC has satisfied its procedural obligations as outlined in Appendix C of its Regional Delegation Agreement. However, NERC offers concerns and suggestions regarding several of the proposed regional standards that are discussed below.

Summary of Findings

BAL-002-WECC-1 — Contingency Reserves

In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

1. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

2. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

   R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

   R1.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

   R1.2. Capable of fully responding within ten minutes.

   In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

3. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

4. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

FAC-501-WECC-1 — Transmission Maintenance

It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

1. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

2. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

IRO-006-WECC-1 — Qualified Transfer Path Unscheduled Flow (USF) Relief

1. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

2. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

3. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

PRC-004-WECC-1 — Protection System and Remedial Action Scheme Misoperation

1. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

2. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

3. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

4. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

TOP-007-WECC-1 — System Operating Limits

1. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

2. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

VAR-002-WECC-1 — Automatic Voltage Regulators

1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

   More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

VAR-501-WECC-1 — Power System Stabilizer

1. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

2. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a

justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

3. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

Conclusion

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC's Response to NERC's Comments
August 13, 2008
Draft

INTRODUCTION

WECC appreciates NERC staff's evaluation of the proposed WECC Regional Reliability Standards (RRSs) in accordance with NERC's Regional Reliability Standards Evaluation Procedure. These proposed WECC RRSs were developed as permanent replacements for the eight WECC Tier 1 RRSs that previously were approved by NERC and FERC. WECC asserts that the seven proposed standards contain all the performance elements of a Reliability Standard that are contained in the NERC Reliability Standards Development Procedure. In addition, the seven proposed standards address and implement the refinements directed by FERC's order on June 8, 2007 (see FERC Docket No.
RR07-11-000) and requested by NERC in its letter dated January 9, 2007. Finally, these proposed standards implement refinements to the approved WECC Tier 1 RRSs which were recommended during the previous expedited direct translation standard development processes.

The attached WECC responses individually address each NERC comment. However, many of the comments submitted by NERC staff relate to refinements that NERC has made to the format of its Reliability Standard Template. These refinements have not been formally approved by NERC, nor have they been transmitted to the regions for comment or additional information, and were therefore unavailable to WECC during the development process. Consequently, WECC has determined not to reopen the standards development process at this stage to address these non-substantive formatting concerns. In addition, during the standards development process, WECC staff twice requested that NERC staff review the proposed WECC standards. WECC did this to ensure that the WECC standard drafting teams were complying with NERC's Regional Reliability Standards Evaluation Procedure as well as its Reliability Standards Development Procedure. NERC did not perform the evaluation of these proposed standards until WECC had completed its Process for Developing and Approving WECC Standards. WECC intends to implement the requested formatting refinements and any potential FERC-directed changes during the next revision of these standards or the next FERC compliance filing.

The proposed WECC RRSs were considered and adopted pursuant to the Process for Developing and Approving WECC Standards. Unless they are approved in their current form, WECC will have to reinitiate the entire process. The consequences of rejecting these WECC RRSs in their entirety would be counterproductive to reliability in the Western Interconnection.

The proposed WECC RRSs will enhance reliability in the Western Interconnection and they will significantly improve the existing eight WECC RRSs because they:

1. Implement ordered NERC and FERC refinements to the existing standards ordered;
2. Eliminate conflicting NERC and WECC requirements contained in the existing RRSs;
3. Include all the Performance Elements of a Reliability Standard;
4. Clarify existing WECC RRSs;
5. Align better with NERC's Functional Model, and
6. Address industry stakeholder concerns.

Therefore, WECC requests the NERC staff recommend approval of these standards to the NERC Board and FERC.

WECC's responses to NERC's initial evaluation are provided in Attachment 1.

Attachment 1

NERC's Written Comments
July 30, 2008
WECC's Written Responses
August 13, 2008

Summary of Findings

BAL-002-WECC-1 — CONTINGENCY RESERVES

NERC COMMENT:
In the review of BAL-002-WECC-1, NERC identified several areas for either clarification or opportunities for improvement. Some of the findings point out approaches potentially inconsistent with FERC either directives or concerns with the clarity of the standard. Other NERC comments simply offer areas for improvement.

5. This standard contains a method for Reserve Sharing Groups or Balancing Authorities (BA) that are not members of a Reserve Sharing Group to maintain a level of Contingency Reserves and the standard describes in Requirement 1.1. how to determine the amount of reserves. NERC suggests that instead of describing the formula narratively (Requirements R1.1.1. to R1.1.2.) WECC include the actual equation in the requirement to reduce ambiguity.

WECC RESPONSE:
1. The requirements in the BAL-002-WECC-1 Standard as written are clear. Industry stakeholders did not submit any comments questioning the clarity of the standard, nor did they identify a need for an equation. The drafting team does not believe there is any ambiguity in the requirements.

NERC COMMENT:
6. Requirement R2 is of concern because it is unclear whether the requirement limits the use of Demand Side Resources (DSM) to fifty percent of the Contingency Reserves. Requirement R2. states:

> **R2.** Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*
>
> **R2.1.** Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.
>
> **R2.2.** Capable of fully responding within ten minutes.

WECC RESPONSE:
2. The drafting team wrote the BAL-002-WECC-1 Standard to permit load, Demand-Side Management (DSM), generation, or another resource technology that qualifies as Spinning Reserve or Contingency Reserve to be used as such. In the case of DSM, the declared amount would be required to respond automatically to frequency deviations and be capable of fully responding in 10

minutes. Loads and DSM are not allowed as Spinning Reserve because it is not permitted by the NERC Spinning Reserve definition. NERC requires that the BAL-002-WECC-1 Standard drafting team use NERC's Spinning Reserve definition. If NERC were to modify its Spinning Reserve definition to allow frequency responsive load tripping as part of a Balancing Authority's DSM, then its use would be permitted under the requirements of the BAL-002-WECC-1 Standard as proposed.

NERC COMMENT (continued):

In the first instance, the NERC Glossary of Terms defines Spinning Reserve as "(u)nloaded generation that is synchronized and ready to serve additional demand." In this regard, spinning reserve, as a component of contingency reserves, is limited to the use of generation. In Order 693 at Paragraph 333, the Commission directed NERC to "treat DSM comparably to conventional generation as a resource for contingency reserves." In addition, the Commission in Paragraph 335 of Order No. 693 directs "the ERO to explicitly allow DSM as a resource for contingency reserves…" NERC believes that the proposed regional standard is in potential conflict with the Commission's directive regarding the use of DSM. In order to eliminate this potential conflict, NERC suggests that WECC explicitly include DSM in Requirement R3. as an additional sub-requirement in the list of acceptable types of reserves in support of the FERC directive. Alternately, NERC requests that WECC clarify how the proposed regional standard supports FERC's directives.

WECC RESPONSE (continued):

DSM that is deployable within 10 minutes is a subset of Interruptible Load. Interruptible load is defined in requirement R3.2 as an acceptable type of Contingency Reserve. As described previously, if NERC modifies its Spinning Reserve and Interruptible Load definitions, then it would be clear that qualifying DSM is permitted as part of Spinning and Contingency Reserves.

NERC COMMENT:

7. In Requirement R1., the proposed standard changes the amount of the contingency reserves that a BA is required to the sum of 3 percent of the total load plus 3 percent of the total generation. This replaces the existing 5 and 7 percent load responsibility served by hydro and thermal generation, respectively. WECC did not provide an explanation for the change and NERC requests that WECC provide information to support this modification.

WECC RESPONSE:

3. The drafting team wrote a paper titled "WECC Standard BAL-002-WECC-1 Contingency Reserves" that provides an explanation supporting the modification. The paper was included as part of the standards approval package filed on June 11, 2008 with NERC.

NERC COMMENT:

8. While the standard does contain Violation Severity Levels (VSLs) NERC suggests that for consistency with the continent-wide standards, the VSLs should be presented in table format.

WECC RESPONSE:

4. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

FAC-501-WECC-1 — TRANSMISSION MAINTENANCE

NERC COMMENT:
It appears that WECC has addressed the NERC and FERC directives in FAC-501-WECC-1.

3. NERC suggests capitalizing defined terms such as Transmission Facilities in the standard.

WECC RESPONSE:
1. "Transmission Facilities" is not a NERC-defined term in the NERC "Glossary of Terms Used in Reliability Standards" document, although "Transmission" and "Facility" are. The standard drafting team did not capitalize "transmission facilities" because it believes that the combination of these two defined terms was too limiting. WECC recognizes that this may create confusion and it proposes to address this issue during the next revision of these standards or the next FERC compliance filing.

NERC COMMENT:
4. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:
2. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>IRO-006-WECC-1 — QUALIFIED TRANSFER PATH UNSCHEDULED FLOW (USF) RELIEF</u>

NERC COMMENT:

4. NERC is concerned that the technical elements of the proposed standard have been removed from the current FERC-approved version of the regional standard. As presented, the proposed standard does not require the mitigation of an overload, which is the express purpose of the standard. The current version of the standard in effect, IRO-STD-006-0, contains technical provisions for the mitigation of an overload that supports the purpose statement. These provisions have not been translated into the proposed replacement standard. NERC requests that a technical rationale be provided for the removal of the technical details in the proposed standard because as proposed it is unclear that the revised standard meets the purpose of the standard, "(m)itigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths."

WECC RESPONSE:
1. The proposed IRO-006-WECC-1 Standard contains all the key reliability requirements and technical elements from the Unscheduled Flow Mitigation Plan (UFMP) that were included in IRO-STD-006-0. The proposed IRO-006-WECC-1 Standard uses NERC's Functional Model terminology to mitigate unscheduled flow <u>during the next operating hour</u>. It is not necessary to reference the remainder of the UFMP because the remaining items contain procedural requirements explaining "how," not "what." The proposed IRO-006-WECC-1 Standard includes requirements to reduce schedules, which then require adjustments to generation patterns. This prevents potential overloads <u>during the next operating hour</u>. Importantly, the requirements for mitigation of an actual (real-time) overload are contained in TOP-007-WECC-1.

NERC COMMENT:

5. The proposed standard includes the term Transfer Distribution Factor (TDF) that is a defined term in the NERC Glossary. The NERC definition is "(t)he portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)." The WECC proposed definition for TDF is "(t)he percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented." *[See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]*

   There are inconsistencies between the two definitions that must be resolved. It is not clear if there are intended differences between the NERC and WECC definitions. If not, NERC suggests removing the WECC proposed term from the standard. If there are intentional differences, NERC requests that WECC determine if they are able to utilize the NERC definition, and if not, to define a new term to accomplish the desired objectives.

WECC RESPONSE:

2. WECC acknowledges the difference between the NERC and WECC definitions for Transfer Distribution Factor (TDF). This is caused by the differences between the Eastern Interconnection Transmission Loading Relief process and the Western Interconnection UFMP. This difference in definitions exists even today between the existing FERC-approved IRO-STD-006-0 Standard and the NERC Glossary. Rejecting the proposed standard will not resolve this difference. WECC will work with NERC to resolve this and intends to make any necessary refinements during the next revision of this standard or the next FERC compliance filing. Despite the difference in the TDF definitions, **the proposed standard corrects a basic difference between the existing FERC-approved IRO-STD-006-0 Standard, which places reliability responsibilities upon the Load Serving Entities (LSEs), and the NERC Functional Model.** LSEs do not have the ability to ensure the implementation of the schedule adjustments required in the existing FERC-approved IRO-STD-006-0 Standard.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

5. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

<u>PRC-004-WECC-1 — PROTECTION SYSTEM AND REMEDIAL ACTION SCHEME MISOPERATION</u>

NERC COMMENT:

5. The PRC-004-WECC-1 proposed standard contains explanatory text in the Applicability section that is redundant with text in the Requirements section. NERC suggests resolving this redundancy by removing the explanatory text in the Requirements section.

WECC RESPONSE:

1. WECC recognizes that the standard drafting team included explanatory text in the requirement section in an attempt to clarify the requirements. However, the duplication does not adversely

impact the applicability, clarity, or the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

6. In Requirement R1., R1.1., and R1.2. NERC suggests that while System Protection personnel may perform the tasks required, the requirement should only apply to the responsible entity specified in the Applicability section to reduce ambiguity. The responsible entity should determine how best and who should perform the activity in practice.

WECC RESPONSE:

2. WECC recognizes that the standard drafting team included System Operators and System Protection personnel in the requirements. R1. of PRC-004-WECC-1 states that, **"System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection Systems and RAS operations."** As written the requirement is sufficiently clear and well-defined to be enforceable on the entities in the Western Interconnection. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

7. Requirement R2. contains text that WECC might consider placing in a footnote as explanatory text.

WECC RESPONSE:

3. WECC recognizes that the standard drafting team included explanatory text in the requirement section that might be more appropriately included as a footnote. However, the text clarifies the requirements. WECC will address this recommendation during the next revision of this standard or the next FERC compliance filing.

NERC COMMENT:

8. Technical clarity is suggested in R2., R2.1., R2.2.1., and R2.2.2. There is sufficient ambiguity in the interplay between the main and sub-requirements that NERC suggests be addressed by streamlining the requirement language. In addition, this appears to be a set of sequential requirements that would benefit from an optional flowchart for applicable entities use as a reference.

WECC RESPONSE:

4. The requirements in the PRC-004-WECC-1 Standard are clearly written. Industry stakeholders did not submit any comments questioning the clarity of the standard. The alternative standard drafting formats or language used in this standard, are applicable exclusively to the Western Interconnection. These stylistic differences do not affect others and should not be a consideration for NERC approval.

TOP-007-WECC-1 — SYSTEM OPERATING LIMITS (SOLs)

NERC COMMENT:

3. The proposed regional standard serves to eliminate a number of the requirements in the previously approved version in effect today. As such, the proposed standard lacks the basis to be a regional standard in that it no longer provides the more stringent requirements necessary to ensure reliable

operation within the Western Interconnection as the legacy requirements now reside in existing NERC standards. For the two requirements that remain, WECC should consider enhancing the current Regional Differences in the continent-wide FAC standards to include the SOL 30 minute operating limitation and net schedule adjustment.

WECC RESPONSE:

1. In the Western Interconnection, SOLs are designed so that during steady-state operations, with all lines in service, the system is at least two contingencies away from cascading. Therefore, exceeding an SOL for the 40 major paths identified in the TOP-007-WECC-1 Standard would not typically qualify as an Interconnection Reliability Operating Limit (IROL) under NERC's TOP-007-0 Standard. The standard drafting team created the TOP-007-WECC-1 Standard to limit the amount of time that a SOL may be exceeded for these very important paths, which makes the TOP-007-WECC-1 Standard more stringent than the NERC standard.

NERC COMMENT:

4. The proposed standard refines the time limit for stability limited paths to 30 minutes which is different than originally stated in WM1 of TOP-STD-007-0. NERC requests WECC to provide the basis for this refinement as it was not included. Further, it is unclear whether this is a more stringent requirement or standard than presented in the existing TOP-STD-007-0 standard.

WECC RESPONSE:

2. The existing standard created confusion during system operation because system conditions may change the limiting conditions on a path. This is because the limit depends upon whether thermal, stability, or post transient limitations are the limiting factor. In addition, having different response times for paths (and sometimes for the same path depending on current outage conditions), complicates system operation, causing delays in responding to the path overload. This resulted in path operators implementing more drastic actions to respond to a contingency within 20 minutes, which may put the system at greater risk, particularly during heavy load periods such as summer. The standard drafting team determined that changing the standard from a 20-minute to a 30-minute response time is insignificant in terms of the probability of a next contingency occurring. Moreover, the drafting team believes that following a system disturbance, the system operators will be better able to identify what generation to ramp in order to be effective in mitigating the overload. This will also allow them to coordinate with others before implementing the generation ramps. Therefore, the simplification of the standard to one consistent 30-minute period improves reliability. It is important to recognize that in spite of extending the recovery period, the refinement should improve system reliability.

VAR-002-WECC-1 — AUTOMATIC VOLTAGE REGULATORS (AVRs)

NERC COMMENT:

4. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with AVR and automatic voltage control mode in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that AVR on generators shall be kept in service at all times and in automatic voltage control mode unless otherwise directed by the Transmission Operator. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-002-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002a-1 Standard. The 98 percent in Requirement R1. of VAR-002-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002a-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring the AVR to be in service provides for time to start up generating facilities. It also allows for evaluation when the Generator Operators respond to unforeseen events.

NERC COMMENT (continued):
More importantly, given this 98 percent limitation, NERC is seriously concerned that the proposed regional standard is not more stringent than the NERC continent-wide standard VAR-002-1, and therefore, fails the statutory criteria to be considered a regional standard.

WECC RESPONSE (continued):
NERC VAR-002-1a R1. permits the Generator Operator to operate in different modes by simply notifying the Transmission Operator. There are no restrictions on the length of time or reasons for operating in other modes. The WECC 1996 outage reports identified the lack of reactive support from generators with AVRs operating in modes other than voltage control as one of the causes of the WECC 1996 outages. The VAR-002-WECC-1 Standard limits the reasons and time for operating a generator without the AVR in service and controlling voltage, therefore it is more stringent than the NERC VAR-002-1a Standard.

NERC COMMENT

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator or condenser that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the existing standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the AVR in service). The use of peaking units adds to overall system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels, however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

VAR-501-WECC-1 — POWER SYSTEM STABILIZER (PSS)

NERC COMMENT:

4. NERC has comments on VAR-501-WECC-1 similar to the comments for VAR-002-WECC-1. It is unclear why WECC has selected 98 percent of all operating hours as the compliance threshold for synchronous generators equipped with Power System Stabilizer in Requirement R1. when an itemized list of 12 exceptions are identified? The current FERC-approved version of the standard does not include such in service goal but expects that Power System Stabilizers on generators shall be kept in service at all times. NERC requests that WECC clarify the 98 percent goal for in service mode in Requirement R1. of the proposed standard, with specific discussion on the relationship between the 98 percent threshold and the exceptions noted.

WECC RESPONSE:

1. There is no change in the basic 98 percent requirement between the existing standard and the proposed standard. The proposed VAR-501-WECC-1 Standard clarifies the requirement and "Levels of Non-Compliance" contained in the existing VAR-STD-002b-1 Standard. The 98 percent in Requirement R1. of VAR-501-WECC-1 was contained in the "Levels of Non-Compliance" in the existing VAR-STD-002b-1 Standard. The drafting team made this clarification to better align with the essential attributes of a reliability standard contained in the NERC Reliability Standards Development Procedure. The two percent allowed before requiring PSS to be in service provides time for evaluation and to start up generating facilities when Generator Operators respond to unforeseen events.

NERC COMMENT:

5. In addition, NERC has concerns with R1.1. that excludes the hours attributed to the synchronous generator that operates for less than five percent of all hours during any calendar quarter. WECC did not present a justification for this exclusion in the hours to achieve the 98 percent in service mode goal. NERC requests that WECC provide information to support this requirement.

WECC RESPONSE:

2. There is no change in the basic five percent threshold between the exiting standard and the proposed standard. Peaking units often operate, for short periods, at low megawatt levels (below where manufactures recommend placing the PSS in-service). Operating at low megawatt levels makes the PSS ineffective. The use of peaking units adds to over-all system reliability, especially during peak system conditions. The five percent threshold during a calendar quarter permits the continued practice of allowing the operation of peaking units below manufacture PSS in service recommendations.

NERC COMMENT:

6. The proposed standard contains clear Violation Severity Levels; however, NERC suggests utilizing the VSL table format to be consistent with the continent-wide standards.

WECC RESPONSE:

3. WECC recognizes that the unapproved NERC Reliability Standard Template requires the placement of VSLs in a table. As stated previously, WECC intends to implement this refinement during the next revision of this standard or the next FERC compliance filing.

(NERC) CONCLUSION

NERC appreciates the opportunity to provide feedback to WECC regarding the seven proposed regional standards WECC submitted on June 11 2007. In some instances, NERC requests additional clarification on the issues and concerns outlined in this document. Others provide suggestions for improving the quality of the proposed regional standards. NERC has included detailed comments directly in the standards that can be found in Appendix A to this document. NERC has also provided comments directly into the comparison mapping documents WECC submitted along with the seven proposed standards in its submittal request.

NERC looks forward to WECC's response to these comments and ultimately, for WECC's decision on whether to request the NERC Board to approve these proposed regional standards.

WECC RESPONSE

WECC appreciates the opportunity to discuss NERC staff's initial evaluation and report in conference calls on August 4 and 5, 2008 and to provide the written clarifications and responses contained herein. We trust that WECC's responses, along with all the supporting documentation contained in WECC's submissions, provide the NERC staff a comprehensive basis for recommending NERC Board of Trustees approval of all proposed standards. Please direct any questions relating to WECC's response to WECC Director of Standards, Steve Rueckert at steve@wecc.biz or (801) 883-6878.

WECC Responses to FERC Staff Concerns and Questions
Regarding the Proposed WECC Tier 1 Standards
June 17, 2008

I. Contingency Reserves — BAL-002-WECC-1

A. Period of Contingency Reserve Restoration: Does the proposed standard modify the current standard to provide a longer period of time of 90 minutes rather than 60 minutes?

Yes, the requirement to restore contingency reserves within 60 minutes was eliminated in the proposed standard. The current standard requires the restoration of contingency reserves within the first 60 minutes following an event. By eliminating this requirement in the proposed standard, WECC adopts the NERC default standard that requires the restoration of contingency reserves within 90 minutes from the end of the disturbance recovery period.[4]

The 60 minute restoration period required by the current standard was developed and used under a manual interchange transaction structure among vertically integrated utilities. As the electric utility industry restructured, there has been a substantial increase in the number of market participants and interchange transactions.[5] To accommodate the increase in number of interchange transactions and market participants an electronic tagging system was implemented in the Western Interconnection. The adoption of an electronic tagging system that accommodates multiple market participants and a large number of interchange transactions made the current mid-hour reserve restoration more cumbersome and made the inappropriate rejection of reserve restoration transactions more likely because such transactions are outside the electronic tagging cycle.

Eliminating the 60 minute reserve restoration requirement and adopting the NERC requirements results in more efficient communication among Balancing Authorities (BAs) because it aligns the restoration of contingency reserves with the electronic tagging system approval cycle. Adopting the NERC contingency reserve restoration requirements reduces the potential for reserve transactions being inappropriately rejected resulting in improved communication among BAs resulting in improved reliability.

B. Shedding of Firm Load: Does the proposed standard change the treatment of the shedding of firm load compared to the current standard?

No, both standards allow for the shedding of firm load under limited circumstances. The addition of requirement R3.4 in the proposed standard clarified the process. During capacity and energy emergencies, a BA or Reserve Sharing Group (RSG) may use load as non-spinning reserves; that is BAs and RSGs will not drop load to maintain their non-spinning reserve requirement. Rather they will use load as part of their non-spinning contingency reserves.

[4] See NERC Standard BAL-002-0 Requirement R6 and WECC Standard BAL-STD-002-0 WR1.d.
[5] Balancing Authorities in the Western Interconnection approve between 2,500 and 4,500 interchange transactions per day.

This standard emphasizes the responsibility of serving customer load first while at the same time protecting the reliability of the Western Interconnection. Even during capacity and energy emergencies, BAs and RSGs are required to comply with the spinning reserve requirements.

C. Deliverability of Contingency Reserves: Does the proposed standard require that contingency reserves be deliverable?

Yes, nothing has changed with respect to the deliverability of contingency reserves.

D. Interruptible Imports: In the current standard the sink BA is required to carry an additional amount of contingency reserves equal to the amount of interruptible imports. Does the proposed standard have the same requirement?

Yes, the term interruptible imports was eliminated from the proposed standard. It was replaced with the added requirement R1.2 which requires that "If the Source BA designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink BA shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s)." This is an improvement from the current standard because it eliminates ambiguity in the term interruptible imports.

E. Demand Side Management: Did the drafting team comply with FERC Order 693 to explicitly allow demand-side management (DSM) to be used for reserves?

Yes, DSM that is deployable within 10 minutes is a subset of interruptible load. Interruptible load is defined in requirement R3.2 as an acceptable type of contingency reserve.

II. Qualified Transfer Path Unscheduled Flow Relief- IRO-006-WECC-1

A. Is the proposed standard intended to address an actual (real time) overload situation?

No, a different standard TOP-007-WECC-1 covers actual (real time) overload situations. The proposed IRO-006-WECC-1 standard includes requirements to reduce schedules, which requires adjustments to generation patterns, to prevent potential overloads during the next operating hour.

B. Should the Unscheduled Flow Mitigation Plan (UFMP) be incorporated in the IRO-006-WECC-1 by reference?

No, the key reliability portions from the UFMP are incorporated in the proposed standard. It is not necessary to reference the remainder of the UFMP.

C. Does the WECC UFMP need to be updated?

Yes, WECC has initiated the process of updating its UFMP.

III. System Operating Limits—TOP-007-WECC-1

A. Could the language in TOP-007-WECC-1 allow for the system to be less than two contingencies away from cascading and more specifically one contingency away from cascading?

No, the proposed standard is designed such that path operations must be at least two contingencies away from cascading during steady state operations. In real time operations when System Operating Limits (SOL) are exceeded for periods not to exceed 30 minutes, there may be system conditions that are less than two contingencies away from cascading.

B. Could IRO-005-2 Requirements R3 and R5 be interpreted that the power system is being operated two contingencies away from a cascading outage while WECC TOP-007-WECC-1 requirement R1 results in the power system being operated one contingency away from a cascading outage?

No, IRO-005-2 requirements R3 and R5 are consistent with the requirements in TOP-007-WECC-1. In the Western Interconnection SOLs are developed in such a manner that the system operation is at least two contingencies away from a cascading failure. This is implicit in the identification of the SOL derivation. If, however, there is a flow that exceeds the SOL, Transmission Operators (TOP) and Reliability Coordinators (RC) must take proactive immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the transmission path exceed the SOL for more than 30 minutes, thus protecting the system from potential cascading for a subsequent contingency.

C. Do SOL changes within the hour extend the time for compliance?

No, SOL changes within an operating hour do not extend the time for compliance.

IV. Automatic Voltage Regulators and Power System Stabilizers – VAR-002-WECC-1 and VAR-501-WECC-1

A. How does VAR-002-WECC-1 coordinate with the new NERC Standard VAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules?

VAR-002-WECC-1 contains specific, more restrictive, requirements on generator operators regarding the operation of Automatic Voltage Regulators (AVR) that are not contained in the NERC Standard VAR-002-1. The reasons for these more restrictive requirements are to support transfer capabilities in the Western Interconnection and to address the insufficient supply of reactive power identified as a cause of the 1996 system disturbances in the Western Interconnection. The drafting team designed the VAR-002-WECC-1 Standard to limit the reasons for operating AVRs in a mode that does not control voltage and the amount of time permitted for such operations. Generator operators are still required to comply with all the requirements contained in NERC VAR-002-1.

B. Are Power System Stabilizers (PSS) included in either of these standards?

Yes, VAR-501-WECC-1 contains requirements regarding the in-service operation of PSS.

C. Why were the AVR and PSS replacement period extended to two years from 15 months?

The amount of time to replace AVR and PSS was lengthened to accommodate the approval and procurement time frames for AVR and PSS for nuclear power plants, which are two years.

V. Transmission Maintenance – FAC-501-WECC-1

A. Does the FAC-501-WECC-1 standard reduce the number of lines that are subject to this standard to the SOL limiting factors from the lines and facilities associated with the 40 paths thereby reducing the obligation for maintenance?

No, there is no change in the number of lines or facilities subject to the proposed FAC-501-WECC-1 standard.

THE UNSCHEDULED FLOW DRAFTING TEAM'S REPLY TO COMMENTS RECEIVED DURING THE FIRST POSTING OF IRO-006-WECC-1 (COMMENTS WERE DUE NOVEMBER 5, 2007)
NOVEMBER 30, 2007

For the reasons given in the White Paper, Chelan County PUD supports the changes to UFAS contained in the new standard.

If adopted, will BA's need to subscribe to and monitor the WebSAS tool?

Hugh Owen

Reply: The USF Drafting Team thanks you for your support. The Reliability Coordinator (RC) will communicate the curtailment information to you via your tagging system. Subscription to WebSAS may be needed to implement alternate actions pursuant to the Unscheduled Flow Mitigation Plan and communicate that information to the RCs and WECC. Path Operators will need to subscribe to WebSAS to call for relief.

Bonneville Power supports this Standard.

It is a constant challenge to keep LSE scheduling staff up to date on an issue they may only see once a year during their shift. In addition, our Power Scheduling (PSE/LSE) staff are not trained on the Western grid to help resolve reliability issues in other control areas. We have just experienced 4 possible violations due to the tool not working properly. Additional communication from WECC and OATI as well as extensive training on our end may have helped avoid this situation, but I believe the reliability of the system should not be in the hands of LSE's.

In addition, having an LSE do a Reliability curtailment has become a large issue when it comes to liquidated damages.

Thanks to the Drafting Team for helping to address and resolve issues around Unscheduled Flow.

Brenda Anderson

Reply: The USF Drafting Team thanks you for your support.

WECC Reliability Coordination Comments Work Group (RCCWG) Comments
RCCWG Members Commenting on this draft standard:
Nancy Bellows, WACM
Terry Baker, PRPA
Paul Bleuss, CMRC
Jeremy Brownrigg, RDRC
Mike Gentry, SRP
Robert Johnson, PSC
Greg Tillitson

The WECC RCCWG has understood from interaction from the WECC Standard IRO-006-WECC-1 Standard Drafting Team that the standard drafting team believed that the WECC Reliability Coordinators should participate in the process of initiating the curtailment of Contributing Schedules to reduce flow in accordance with Attachment 1-IRO-006-WECC-1 for the purpose of verifying that the curtailment request was valid. WECC RCCWG members were told that once a Transmission Operator of a Qualified Transfer Path requested a curtailment, the curtailment would automatically occur in 5 minutes if the WECC Reliability Coordinator did not cancel the Transmission Operator notification.

With this in mind, the measures and violation severity levels of non-compliance for Requirement R1 all point to time required past the allowed five minutes for initiation of curtailment of contributing schedules by the WECC Reliability Coordinator. All of these seem inconsistent with the knowledge that the curtailment is an automated process. The WECC RCCWG suggests that the standard drafting team consider using a measure and violation severity levels associated with a WECC Reliability Coordinator cancellation of curtailment.

WECC RCCWG
Nancy Bellows

Reply: The drafting team made refinements to R1 and the severity level associated with R1 to address the RCCWG's concerns. Also, in Measurement M1, the drafting team clarified the cancellation of a curtailment is not a violation.

The following comments refer to the White Paper.

The standard states that LSE's may have the option of selecting which schedules to curtail for compliance. Ultimately, it is the Balancing Authorities that are responsible for USF mitigation. Therefore, Balancing Authorities should have the same privileges that LSE's have when it comes to selecting which schedules to curtail.

Requirement 2 states: "Once the Source and Sink Balancing Authorities receive Curtailment requests through their tagging systems, the Balancing Authorities must actively approve the curtailment request: implement alternative actions that provide the Relief Requirement; or a combination thereof that collectively meets the Relief Requirement." Alternative actions could include a counter schedule that would cause generation redispatch in a different Balancing Authorities control area. Thereby achieving compliance without actively approving the curtailment request. Based on this, SRP would like to recommend changing the wording in the highlighted sentence to; The Balancing Authorities must approve or deny all USF curtailment requests. This would line up with the wording in Measure 2.

Heinz Ontiveros
Salt River Project

Reply: Implementing this comment would restate INT-006-2 R1. The drafting team does not believe it is appropriate to restate a NERC requirement. Requirement 2's intent is for the Balancing Authority to provide relief. Denial of a curtailment will not necessarily provide relief.

PPL Montana & PPL EnergyPlus support the proposed Standard as currently drafted.

The proposed Standard properly applies decisions and subsequent actions regarding USF to those entities (RCs & BAs) responsible for bulk electric system reliability and removes applicability from marketing entities, such as LSEs and PSEs. Thus, the proposed Standard now aligns with the NERC Functional Model and addresses concerns as directed by the FERC.

PPLM & EPLU appreciate this opportunity to comment and the efforts of the UFAS Standard Drafting Team on this proposed Standard.

Jon Williamson
PPL EnergyPlus

Reply: The USF Drafting Team thanks you for your support.

These comments were posted by WECC staff on behalf of Denise Koehn of Bonneville Power Administration.

BPA is OK with this standard as written.

Reply: The USF Drafting Team thanks you for your support.

The IRO-006-WECC-1 Standard Drafting Team thanks all commenters who submitted comments on the WECC IRO-006-WECC-1 Standard. This Standard was posted for a 30-day public comment period from November 30, 2007 through January 2, 2008. The Standard Drafting Team asked stakeholders to provide feedback on the standard by posting comments on the WECC website. There were two sets of comments from two companies.

In this 'Consideration of Comments' document, stakeholder comments have been organized so that it is easier to see the responses associated with each comment.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Steve Rueckert at 801-582-0353 or at steve@wecc.biz. In addition, there is a WECC Appeals Process.

Comments and Responses

Bonneville Power Administration supports this Standard.

It is a constant challenge to keep LSE scheduling staff up to date on an issue they may only see once a year during their shift. In addition, our staff is not trained on the Western grid to help resolve reliability issues in others control area.

We have just experienced 4 possible violations due to the tool not working properly. Additional communication from WECC and OATI as well as extensive training on our end may have helped avoid this situation, but I believe the reliability of the system should not be in the hands of LSE's.

In addition, having an LSE do a Reliability curtailment has become a large issue when it comes to liquidated damages.

Brenda Anderson

Reply: Thank you for your support.

2-Jan-08

The standards' drafting team has taken a very complex subject and made it into something very usable. The following are comments and suggestions by PPL Energy Plus, LLC ("EPLUW").

Definitions EPLUW would like to see changed or added to:
• Contributing Schedule: Would it be more accurate to clarify that schedules are between zones within BA's rather than just between BA's?

Reply: The definition does not specify that the two Balancing Authorities have to be different. The Source Balancing Authority and Sink Balancing

Authority may be the same Balancing Authority on the tag. Therefore, no change is required to the definition.

• TDF: Include a sentence stating a POS TDF loads the qualified path and a NEG TDF unloads the qualified path. This helps everyone understand the very important TDF sign relationship.

Reply: The definition for positive and negative TDFs is a training issue and should be covered in a training document not the standard. Therefore, the drafting team did not make the requested modification.

• Relief Required:
o The definition is written as if schedule curtailments were the only way to provide relief, when in reality, other actions taken by the sink BA can provide relief. Could the phrase "…result by curtailing each Sink Balancing Authority's Contributing Schedules by…" be replaced with "result by actions of the Sink BA including but not limited to curtailing contributing schedules…"?

Reply: The definition only defines how you calculate the required relief, not how to comply with the requirement. Use of alternative actions to provide the required relief is covered under R2. Therefore, the drafting team did not modify the definition.

o EPLUW would also like to see wording in the definition of Relief Required that requires the Sink BA (when using schedule curtailments to provide relief) to curtail the most effective (i.e. highest POS TDF) schedules first.

Reply: The definition only defines how you calculate the required relief, not how to comply with the requirement. If the drafting team implements this recommendation, it would remove the choice for providing the required relief. The drafting team believes the members want the ability to have a choice.

Possible definitions to include:
• A qualified Transfer Path Event should have a definition in the definitions section. The standard attempts to define Transfer Path Event in section 1.2.1.

Reply: The drafting team moved the definition from 1.2.1 to the definition section. The drafting team also clarified the definition.
The standard should clearly define what is Step 4 and the obligations related thereto and any preceding steps.

Reply: Through inclusion of the table in Attachment 1 WECC IRO-006-WECC-1, the definition of step 4 and all steps is captured.

Section D, Compliance
1.2 Monitoring - Please remove the section stating "Other methods as provided for in the Compliance Monitoring Enforcement Program" from the standard because this program could undergo changes that would not receive due process. Alternately, please list in the standard the provisions in the Compliance Monitoring Program that will be used for this standard.

Reply: The drafting team does not have authority over the compliance monitoring program. The compliance enforcement authority retains the right to modify its program as needed.

Section 1.2.2 – Please re-phrase this section to make it clear that the Compliance Monitoring period starts anew each calendar month (if this indeed is the case).

Reply: The definition for a reset period means that the compliance monitoring period begins again each month.

Section 2 – EPLUW believes Sections 2.2, 2.3, 2.4 are applicable and should be written to prevent more than one instance of the RC missing the 5 minute time requirement. It appears that as written, the standard provides no incentive for the RC to perform after the first violation of the month.

Reply: This is one tool of several that reliability coordinator and transmission operators can use to prevent violations of system operating limits. Transmission Operators are primarily responsible for keeping actual flows to within limits. The drafting team recognizes that inaction on behalf the reliability coordinator will not result in failure of the unscheduled flow mitigation plan because the webSAS tool will implement the curtailment. Therefore, the severity level is low.

EPLUW has no comments on the very clear white paper and thanks the standard drafting team for their hard work.

Reply: Thank you.

John Cummings

Drafting Team IRO-STD-006

FIRST NAME	LAST NAME	COMPANY
Brenda	Anderson	Bonneville Power Administration
John	Cummings	Northwestern Energy
Paul	Humberson	Western Area Power Administration WACM
Tom	Isham	Arizona Public Service Company
Ken	Wilson	WECC
David	Lemmons	Public Service Company of Colorado
David	Lunceford	California Independent System Operator
Phillip	O'Donnell	Sacramento Municipal Utility District
Ken	Otto	Western Area Power Administration
Paul	Rice	WECC
Richard	Salgo	Sierra Pacific Resources, Inc.
Jaison	Tsikirai	PacifiCorp West
Curtis	Winterfeld	Deseret G&T
Chuan-Hsier	Wu	Los Angeles Department of Water and Power

Western Electricity Coordination Council

Operating Committee Meeting

MARCH 6–7, 2008

Albuquerque, NM
Voting Results

1. **Motion:**

The VAR-002-WECC-1 Standard Drafting Team recommends that the OC approve VAR-002-WECC-1 and that after regulatory approval, it shall supersede VAR-STD-002a-1.

Explanation: To ensure that Automatic Voltage Regulators on synchronous generators and condensers shall be kept in service and controlling voltage to help maintain Bulk Electric System reliability.

VOTING CLASS	YES	NO	ABSTAIN
TRANSMISSION PROVIDERS	28	4	2
TRANSMISSION CUSTOMERS	25	11	11
STATE and PROVINCIAL	1	0	0
TOTALS	**54**	**15**	**13**

Result: PASSED

Minority Opinion:

- Please see Appendix A for comments received via email– Comments from AVA, BPEC, EPLUW, Mariner Consulting Services, SMUD and TANC

2. **Motion:**

The VAR-501-WECC-1 Standard Drafting Team recommends that the OC approve VAR-501-WECC-1 and that after regulatory approval, it shall supersede VAR-STD-002b-1.

Explanation: To ensure that Power System Stabilizers (PSS) on synchronous generators shall be kept in service.

VOTING CLASS	YES	NO	ABSTAIN
TRANSMISSION PROVIDERS	32	1	1
TRANSMISSION CUSTOMERS	33	2	10
STATE and PROVINCIAL	1	0	0
TOTALS	**66**	**3**	**11**

Result: PASSED

Minority Opinion:

- Please see Appendix A for comments received via email – Comments from AVA and EPLUW

3. **Motion:**

The BAL-002-WECC-1 Standard Drafting Team recommends that the OC approve BAL-002-WECC-1 and that after regulatory approval, it shall supersede BAL-STD-002-0.

Explanation: Contingency Reserve is required for the reliable operation of the interconnected power system. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

VOTING CLASS	YES	NO	ABSTAIN
TRANSMISSION PROVIDERS	22	6	6
TRANSMISSION CUSTOMERS	36	10	5
STATE and PROVINCIAL	1	0	0
TOTALS	**59**	**16**	**11**

Result: PASSED

Minority Opinion:

- Talking about a reliability standard, the existing standard with a proven track record of over a few decades is being replaced with one that is based entirely on compromise. The result will be a massive shift in cost without any technical studies to justify the shift to 3% generation and 3% load. The suspicion is an overall reduction of reserves carried in WECC without any technical justification. It is better to spend time on a technical based standard like FRR than putting in place a compromise solution in the interim.

- The standard is based on compromise and reducing reliability
- There are a number of market issues with this standard to the point where the entity is not comfortable supporting the standard even though they think it is the right direction
- Please see Appendix A for comments received via email – Comments submitted by BC Hydro, EPLUW, NCPA, NWMT, Powerex, PGE (TP), PGE (TC), PSEI, SCL, SMUD and TANC

4. **Motion:**

The PRC-004-WECC-1 Standard Drafting Team recommends that the OC approve PRC-004-WECC-1 and that after regulatory approval, it shall supersede PRC-STD-001-1 and PRC-STD-003-1.

- **Explanation:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

VOTING CLASS	YES	NO	ABSTAIN
TRANSMISSION PROVIDERS	30	4	0
TRANSMISSION CUSTOMERS	32	2	12
STATE and PROVINCIAL	1	0	0
TOTALS	**63**	**6**	**12**

Result: PASSED

Minority Opinion:

- Please see Appendix A for comments received via email – Comments from AVA, SMUD and TANC

5. **Motion:**

The IRO-006-WECC-1 Standard Drafting Team recommends that the OC approve IR0-006-WECC-1 and that after regulatory approval, it shall supersede IRO-STD-006-0.

Explanation: Mitigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths.

VOTING CLASS	YES	NO	ABSTAIN
TRANSMISSION PROVIDERS	33	0	1
TRANSMISSION CUSTOMERS	39	2	7
STATE and PROVINCIAL	1	0	0
TOTALS	**73**	**2**	**8**

Result: PASSED

Minority Opinion:
No minority opinions were offered at the meeting and none were received via email.

6. **Motion:**

The FAC-501-WECC-1 Standard Drafting Team recommends that the OC approve FAC-501-WECC-1 and that after regulatory approval, it shall supersede PRC-STD-005-1.

Explanation: To ensure the Transmission Owner of a transmission path identified in the table titled "Major WECC Transfer Paths in the Bulk Electric System" including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.

VOTING CLASS	YES	NO	ABSTAIN
TRANSMISSION PROVIDERS	28	4	2
TRANSMISSION CUSTOMERS	30	1	14
STATE and PROVINCIAL	1	0	0
TOTALS	**59**	**5**	**16**

Result: PASSED

Minority Opinion:
- Please see Appendix A for comments received via email – Comments from SMUD and TANC

7. **Motion:**

The TOP-007-WECC-1 Standard Drafting Team recommends that the OC approve TOP-007-WECC-1 and that after regulatory approval, it shall supersede TOP-STD-007-0.

<u>Explanation:</u> When actual flows on Major WECC Transfer Paths exceed System Operating Limits (SOL), their associated schedules and actual flows are not exceeded for longer than a specified time.

VOTING CLASS	YES	NO	ABSTAIN
TRANSMISSION PROVIDERS	30	3	1
TRANSMISSION CUSTOMERS	29	4	13
STATE and PROVINCIAL	1	0	0
TOTALS	**60**	**7**	**14**

Result: PASSED

Minority Opinion:

- Please see Appendix A for comments received via email – Comments from SMUD and TANC

APPENDIX A

REASONS FOR NO VOTES [6]

Scott Kinney, Avista Corp. (AVA)

Here are my reasons for voting no on the following standards:

VAR-002-WECC-1 and VAR-501-WECC-1 - Neither of these standards give the Transmission Operator any discretion to exempt a generator from requiring operation in AVR mode or having PSS in service regardless of the size of the generator or its impact on the BES. The VAR-002-WECC-1 standard applies to any generator connected to the BES. Avista commented during the standard development that the TO should have some discretion (NERC gives the TO some discretion in VAR-002-1) to exempt generators that have no impact on the BES with or without AVR and PSS in service based on their location and/or size. During the standard drafting Avista suggested the standards should require a TO to provide study results to verify there is no impact to the BES and that there should be a MVA size limit on generators that can be exempt from the standards.

PRC-004-WECC-1 - The WECC standard goes way above and beyond the requirements of NERC standard PRC-004-1. Avista does not believe the additional requirements are necessary to ensure that relay and RAS/SPS failures are adequately reviewed. The standard adds additional burden without and inherent benefits.

Thank you for the opportunity to comment.

****

Clement Ma, BC Hydro

BC Hydro has serious concerns regarding the proposed standard BAL-WECC-002. The team that developed the standard has indicated that the 3% load, 3% generation numbers were proposed as a compromise as opposed to being based on a technical evaluation of reserves from a reliability standpoint. In analyzing the costs of the proposal, the team only looked at aggregate impacts for the WECC and the sub regions. However, this analysis misses the significant cost impact that arises for predominantly hydro based Balancing Authorities. BC has operated reliably using the 5% hydro standard for many years. The proposed standard will result in an increase in BC Hydro's operating reserve requirements by almost 1% (close to 100 MW on winter peak) without any technical justification (nor practical justification in light of our reliable operating history) to justify to its ratepayers the increase in cost of holding this additional operating reserve.

****

Julie Martin, BP Energy Company (BPEC)

[6] The reasons for no votes in the appendix were submitted by the individual entities via email after the Operating Committee meeting. The reasons for no votes in the main document were stated at the Operating Committee Meeting in Albuquerque, NM

Of the 7 Standards that were balloted, BP Energy Company (BPEC) voted "No" on 1 Standard. This one Standard was VAR-002-WECC-1 (Automatic Voltage Regulators). BPEC voted "No" on this Standard because we felt the following problems exist in the Standard as proposed:

VAR-002-WECC-1 requires generators to operate in a constant voltage mode at all times, but it does not require the transmission operator ("TOP") to provide the generator with a voltage setting to program into the AVR. To the extent that a TOP provides a reactive power schedule (instead of a voltage setting), it forces the generator operator to manually adjust the voltage settings on the AVR throughout the day in an attempt to maintain the amount of reactive power specified by the TOP.

This places a significant burden on the plant operators since they must manually adjust voltage settings every time the system voltage shifts up or down.

It also poses a significant risk of voltage collapse if plant operators see an increase in reactive output caused by a drop in system voltage caused by a transmission contingency and they manually respond by reducing reactive output to the pre-contingency level. This is exactly the opposite of what is needed when system voltage begins to collapse, even though the generation operators were simply following the reactive power schedule provided by the TOP.

This exposes all parties to a large share of responsibility if a voltage collapse does occur. TOPs will be blamed for failing to provide voltage schedules that would have prevented the manual intervention by generators. Generators will be blamed for doing the wrong thing at the wrong time when they reduced reactive output while the system was collapsing. WECC will be blamed for adopting a flawed standard which authorized TOPs to use this mode of voltage control.

A better alternative to the proposed standard is to include in a WECC standard a requirement that TOPs issue voltage schedules to generators.

****

John Cummings, PPL Energy Plus (EPLUW)

BAL-002-WECC-1 Contingency Reserves

While EPLUW believes that the redrafted BAL-002 is an improvement, EPLUW voted no because there is an inconsistency between the proposed reliability requirement and the method in which reserves are procured and provided under the existing Open Access Transmission Tariffs (OATT). Transmission Providers (TP) must generally offer operating reserves under their OATTs to Transmission Customers serving load in the TP's Control Area. Otherwise, there is no default supplier of reserves. Further, the implementation of the proposed standard has not been fully explained, and it is unclear if reserves will be available to all market participants that may be required to procure or provide them in the future. EPLUW would like to see these issues addressed before the standard becomes effective.

VAR-002-WECC-1 Automatic Voltage Regulators

EPLUW voted no because the proposed standard does not have a grandfathering provision to address existing, older generating units that may not meet the proposed requirement.

VAR-501-WECC-1 Power System Stabilizer

EPLUW voted no because the actual reliability standard (not WECC policies) should include an explicit description of which units must have PSS's (including which units are grandfathered), and this criteria should be subject to change in accordance with the standard development process.

****

John Stout, Mariner Consulting Services

Why the WECC Automatic Voltage Regulator Standard (VAR-002-WECC-1) Should Not be Approved as Currently Proposed

At the March OC meeting, a significant number of WECC Generation Operators voted against acceptance of the proposed WECC AVR standard. Most did so because this standard allows Transmission Operators to direct generators to operate in a manner which exposes WECC to a significant and unnecessary risk of voltage collapse, and exposes those generators to increased and unreasonable risk of incurring non-compliance penalties.

One of the important lessons learned in the July/August 1996 WECC blackouts was that operation of generation in a constant reactive power mode increased the risk of voltage collapse and, therefore, should be limited in WECC. The technical reason for this conclusion is the fact that when voltage begins to collapse, increased reactive power output is required in order to raise the voltage and prevent it from collapsing to the point of causing a blackout. Therefore, WECC established a requirement that, with ten exceptions, generation controls had to be operated in the constant voltage mode of operation. In this mode of operation, if voltage declines, the generator automatically increases and maintains its reactive power output until the voltage returns to normal. That requirement is the genesis of the proposed WECC AVR standard.

WECC Generation Operators support the requirement that their AVR's be operated to maintain voltage and automatically respond with increased reactive output to prevent voltage collapse.

However, not all WECC Transmission Operators allow interconnected Generation Operators to provide voltage responsive reactive support. Certain Transmission Operators have refused to provide voltage schedules to their Generation Operators. They are allowed to do this because the proposed WECC AVR standard does not include a requirement that Transmission Operators provide voltage schedules. Instead, the WECC AVR standard is silent on this issue, allowing Transmission Operators to follow less restrictive NERC standards which afford them the option of providing reactive power schedules rather than voltage schedules. This practice forces Generation Operators to manually adjust their AVR voltage setting by trial and error to find a voltage setting that will provide the exact amount of reactive power directed by the Transmission Operator. Since the voltage on the transmission grid varies throughout the day, the Generation Operator is forced to continuously reset the voltage on the AVR. This is an unnecessary and distracting manual control burden on the Generation Operator. It effectively eliminates the "Automatic" in "Automatic Voltage Regulator."

NERC VAR-002 requires the Generation Operator to comply exactly with the voltage schedule or reactive power schedule directed by the Transmission Operator. If the Transmission Operator provides a voltage schedule, the AVR can automatically maintain compliance with the NERC standard. If the Transmission Operator refuses to provide a voltage schedule, and instead insists on providing a reactive power schedule, compliance can no longer depend on the automatic operation of the AVR. The proposed WECC AVR standard prohibits the AVR from being switched to a constant reactive power mode of operation. Instead compliance becomes totally dependent on constant attention and readjustment by the Generation Operator. This significantly increases the risk of reliability standard non-compliance for the generator.

Even more disturbing is the fact that this situation (the Transmission Operator specifying a constant reactive power output rather than a constant voltage level) defeats the intended purpose of the WECC AVR standard, to prevent a voltage collapse. If voltage does begin to collapse, the generator AVR, operating in constant voltage mode, will increase the reactive power output from the unit. That increase in reactive output means that the generator will no longer be producing the amount of reactive power specified by the Transmission Operator's reactive power schedule. Once this occurs, the Generation Operator must immediately reduce the reactive power provided by the generator or risk fines for noncompliance with NERC standard VAR-002, R2. That will result in the generator doing the exact opposite of what is needed to prevent a voltage collapse and exposes WECC to a risk of blackout.

This issue was repeatedly raised during the standards development process, but the drafting team took the position that it was not a problem that needed to be addressed by the WECC AVR standard. During the March vote at the OC, an amendment was proposed to resolve this issue by adding a requirement to the WECC AVR standard that Transmission Operators provide voltage schedules instead of reactive power schedules. No one expressed an opinion that the concerns raised by generators regarding the reliability risk to WECC were invalid, yet the proposed solution was overwhelmingly rejected by the OC. Unfortunately, due to the voting structure of the OC, the concerned Generation Operators are in a minority and could do nothing more to resolve this issue.

The WECC Board should not take the same path as did the drafting team and the Operating Committee. We believe the Board should do at least three things before approving this standard.

First, the WECC Board should ask the OC to report on the validity of the reliability risk and the compliance risk described above. If their response results in a Board conclusion that either risk if valid, the following additional questions should be should be raised by the Board.

The WECC Board should ask the OC to provide specific information on which Transmission Operator's provide reactive power schedules rather than voltage schedules to their interconnected generators. This information should include the specific reasons why such Transmission Operator's have chosen to provide reactive power schedules and explain why those reasons outweigh the reliability and compliance risk created by reactive power schedules. If the Board concludes those reasons are not sufficiently justified, the Board should remand this AVR standard for inclusion of a voltage schedule requirement.

If valid reasons are provided to the preceding question, the WECC Board should ask the OC to explain why each of those reasons were not included with the ten exceptions already listed under R1 of the WECC AVR standard. If the OC cannot justify why those reasons should not be included in the ten exceptions, the Board should remand the standard until those reasons are included. By adding such reasons to the list of exceptions, Generation Operators should be allowed to place their AVR in the automatic control mode that matches the reactive power schedule provided by the Transmission Operator (i.e. Constant MVAR mode for VAR Schedules or constant Power Factor mode for Power Factor Schedules.)

While Board members may feel a reluctance to not support the OC recommendation to approve the currently proposed AVR standard, each Board member should recognize an important distinction between votes at the OC and votes by the Board. Standing Committee members are entitled to vote in accordance with their self interests. Board members have a different standard. Board Members are obligated to vote what is best for WECC. That difference can cause Board votes to sometimes result in different outcomes than Standing Committee votes. While our position was the minority opinion within the OC, we firmly believe it to be the best path for maintaining the reliability and credibility of WECC.

****

Fred Young, Northern California Power Agency (NCPA)

NCPA reviewed this standard prior to the OC meeting and from an operating/reliability perspective has no objection to the proposed changes to BAL-STD-002-0. However, based on discussions with our trading personnel and counter-parties, there is significant confusion as to the impacts of the change from 5%hydro/7%thermal to 3%generation/3%load in the calculation of a BA's Contingency Reserve requirement. The market is saying that the 3% of load portion will be passed on to the LSE irrespective of the LSE's location, i.e. in the Source BA or Sink BA. This confusion was further reinforced by Mr. David Lemmons response to a question from Powerex concerning cost shifts. Mr. Lemmons' response is that it is time for the load to carry their share.

This standard, BAL-002-WECC-1 does not contain language that moves any contingency reserve responsibility to the load. It only changes how the Contingency Reserve requirement for a BA or Reserve Sharing Group is calculated. It is evident by one of the author's comments, Mr. Lemmons, that there are some significant market changes that will result from implementation. Without clarification of these market impacts, NCPA could not support BAL-002-WECC-1.

NCPA fully supports standards that enhance reliability. But reliability at any cost or unknown cost is unacceptable.

The foregoing is why NCPA did not support BAL-002-WECC-1.

Thank you for your consideration.

****

Marc Donaldson, North Western Energy (NWMT)

Reasons for NorthWestern Energy (NWMT) No Vote on WECC Standard BAL-002-WECC-1 – Contingency Reserves

On March 6, 2008, NorthWestern Energy (NWMT) voted No on WECC Standard BAL-002-WECC-1 – Contingency Reserves for the following reasons:

1. Although the amount of required reserves stated in R1.1.2. (sum of three percent of the load and three percent of net generation) may make the determination of required reserves easier than the prior five percent of hydro and seven percent of thermal and, although the previous five and seven percent was determined arbitrarily, the "three plus three" approach is still arbitrary and may negatively impact reliability of the Western Interconnection.

2. The standard may result in an unfair shift of reserve obligation, which may also result in a shift of costs.

****

Mike Ryan, Portland General Electric (PGE), Transmission Provider

This is in response to your request for the reasons behind NO votes on BAL-002-WECC-1.

As you well know, I have been voicing my concerns over the direction that this drafting team has taken at every opportunity to change the WECC's contingency reserve requirements. I have regularly offered comments on the posted drafts, but have seen little change in the contents.

My comments about the reliability consequences of BAL-002-WECC-1 are these:

- The "Tier One" BAL-STD-002-0 reflects the current WECC MORC by breaking down required operating reserve into four components: regulating reserve, contingency reserve, reserve for on-demand obligations, and reserves for interruptible imports. The proposed BAL-002-WECC-1 narrows the scope to only contingency reserve, which raises the question of what happens to the other components. NERC BAL-002 adequately covers regulating reserve, but includes no provisions for on-demand obligations or interruptible imports. BAL-002-WECC-1 does include some language for on-demand obligations, but only as contingency reserve; no other types of on-demand rights are addressed.

  It's not clear to me how the decision to narrow the scope of the WECC BAL-002 standard will affect the current requirements in the WECC MORC. This should have been made clear in the proposal. I hope the Board will make it clear that BA's must still carry additional operating reserves to account for on-demand obligations and interruptible imports.
- The "load responsibility" concept helped characterize the nature of the transactions. For the "sink" BA, it identified those imports that were "firm for the hour". Simplifying the calculation of contingency reserve does NOT relieve the BA from anticipating which imports might be interrupted in-hour, and therefore what additional reserves need to be available. The recently adopted clarification of "load responsibility" and e-tag 1.8 made it easier. Now it seems everyone will be forced to parse the energy codes to infer what's "firm for the hour".

  It would be helpful if the Board directed members to continue to use the "load responsibility" feature in e-tag 1.8 to clearly identify those transactions that are not "firm for the hour".
- Despite voiced concern over the difficulty of interpreting "load responsibility", the drafting team saddled WECC BAL-002 with "interruptible load". As a BA, I do not want to be put in a position to judge whether or not loads offered up by an LSE meet the contract requirements of being "interruptible".

I also have a comment not related to reliability. Or rather, a comment that the changes made through BAL-002-WECC-1 don't seem to be prompted by genuine reliability concerns (only thinly disguised in them). At their heart the changes seem to be driven more by the economic interests of some to shift contingency reserve responsibility (i.e. costs) from the generators to the loads (and perhaps the new MIC mantra that transactions can't have reliability implications). I'd like to think that reliability changes should be driven by technical merit weighed against overall costs, and that the Board will not allow the WECC's standards process to be used as a lever to shift costs among members.

You'll also remember that I've frequently found myself defending the drafting team's right under WECC "due process" to produce their draft as they see fit, however to my eyes the results are far from pretty. This standard, combined with the NERC/FERC ability to trump WECC "due process" (e.g. sanction tables), raises serious doubts in my mind to about the workability of WECC standards process.

****

JJ Jamieson, Portland General Electric (PGE), Transmission Customer

Portland General Electric voted against BAL-002-WECC-1 at the 3/6/08 meeting in Albuquerque, New Mexico.

Portland General Electric Merchant posted the following comments 02/21/08 in response to the posting of BAL-002-WECC-1 for review before voting at the upcoming Operating Committee meeting in Albuquerque, New Mexico. Our comments have not been responded to in any forum since posting.

> "Portland General Electric Merchant is concerned with the movement toward unnecessary changes to the approved standard proposed in BAL-002-WECC-1 particularly due to the motivation being cited. At no time should the basis of a reliability standard be centered on "a compromise" rather than the requirements of operational reliability.
>
> In public meetings held with / by the BAL-002-WECC-1- drafting team there was no evidence presented that illustrated increased reliability under BAL-002-WECC-1. The meetings showed that in fact BAL-002-WECC-1 could result in a reduced level of reliability in the WECC region.
>
> Why is a reliability entity allowing a compromise on standards that impact reliability? We are all being held to these standards and they should be defined by what is necessary for reliability, otherwise it isn't a reliability issue and the market will define the products.
>
> The biggest deficiency of this "compromise" is that it assumes that we have a robust and fully functioning market for reserves. To our knowledge most merchants do not have the right to sell reserves, let alone have extra to sell, and there has not been any formal discussion of how cost based entities can function in a WECC region reserves market. We need to agree that reserves are a reliability issue in determining use and level but a market issue when determining responsibility.
>
> The public meetings showed the proposed BAL-002-WECC-1 move towards the creation of a market product rather then a reliability standard.
>
> WECC has been very clear that the definition of market products is not within their mandate "WECC should focus on the interpretation of reliability criteria. It should not

define energy market products." (Load Responsibility July 26, 2007) and it is equally as clear that the proposed BAL-002-WECC-1, while perhaps not intentionally, will result in the definition of a new energy product albeit not named by the standard itself.

Is it WECC's intention, with BAL-002-WECC-1, to create an energy product leaving only the naming of said product to the WSPP and other like entities?

Portland General Electric Merchant encourages the BAL-002-WECC-1 drafting team to work towards the establishment of a standard that is focused on the reliability of the system rather then a compromise that defines a market product.

Portland General Electric Merchant"

It was communicated at the Operating Committee meeting that we should pass BAL-002-WECC- 1 because 'WECC doesn't want to go to FERC and request an extension.' Is this appropriate reasoning when dealing with issues affecting reliability?

We are concerned that BAL-002-WECC-1 is assuming a robust reserves market in the West. The West doesn't have a mature reserves market and this will put additional burden on the load serving merchants by forcing them to procure reserves from the generators in order to meet the new standard. How does WECC propose BAL-002-WECC- 1 will be able to sustain a reliable system absent a robust reserves market?

We echo Puget Sound Energy's concerned that BAL-002-WECC- 1 will result in a cost shift between Market participants without any additional reliability being realized.

Portland General Electric also agrees with Powerex in that there simply was not an appropriate level of analysis down to support a wholesale change in how reserves are handled in the WECC.

Finally, Portland General Electric states again that reliability standards should not be based on compromise but rather careful consideration of what will provide the most reliable and effective system.

Thank you for the opportunity to comment

****

Mike Goodenough, Powerex (PWX)

Powerex agrees with the explanation for voting "No" to BAL-002 offered by BC Hydro.

In addition, Powerex would add that the proposed standard will require changes in markets that have not yet been considered. While we are supportive of the objectives to bring clarity to how reserve obligations are determined and commend the team for making progress in obtaining that clarity, no consideration was provided for how implementation of the new standard might impact the existing market and transmission tariff structures and what new uncertainties might be created. This should be considered so that we do not incur unnecessary adaption costs, which would then be followed by additional costs to implement the Frequency Response Reserves standard, which is a far more technically sound approach to re-examining the way reserve requirements should be calculated. BC Hydro and Powerex believe that this consideration should occur before the standard is adopted.

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Gary Nolan, Puget Sound Energy (PSEI)

PSEI, as a TP, only voted "No" on BAL-002. Our explanation is summed up by the comments Joe Hoerner from PSEM posted on the WECC website with our agreement.

Puget Sound Energy (PSE) appreciates the opportunity to provide comments on the proposed WECC Standard BAL-002-WECC-1 (Contingency Reserve). These comments are provided on behalf of Puget Sound Energy's transmission and merchant functions.

Upon review and analysis of the proposed Standard BAL-002-WECC-1, PSE can not determine how this standard provides any additional reliability over today's standard. The proposal alters the calculation for contingency reserves instead of clearly defining how contingency reserves would be activated to ensure system reliability. Furthermore, PSE's analysis indicates that adoption of this standard will result in significant cost shifts from generators to load-serving entities. PSE's ratepayers could expect to pay an additional $14,000,000 more per year in increased contingency reserve obligations without any added reliability benefit. PSE cannot find any legitimate reason as to why our regulating entities could justify our approval of such a cost increase with no benefit. If, in fact, the primary justification for creating the standard is to firmly establish the obligation of where the reserve obligation lies, then we feel it is more appropriate to address this issue in the commercial forum.

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Pawel Krupa, Seattle City Light (SCL)

I have to apologize for being late in responding to your e-mail.

On the behalf of SCL I cast NO vote for the BAL-002-WECC-1 standard. In preparation for the OC meeting I attended the BAL-002-WECC-1 workshop in Portland and we discussed this standard internally within SCL. Based on our internal discussions we believed we could not support this standard at its current version. Below are some of the reasons that we are not supporting this proposed standard as currently written:

1. Requirement R.1. The proposed standard changes the amount of contingency reserves required to carry by the BA's to 3% of the BA's total generation and 3% of the BA's total load. The current WECC standard BAL-STD-002-0 requires to carry 5% reserves for load responsibility served by hydro generation and 7 % served by thermal generation. We believe that there is no technical explanation for the new allocation of 3% generation and 3% of load. The 5% and 7% allocation was based on system data collected during the previous system disturbances and it provided safe contingency reserve margin during many severe disturbances in WECC interconnection. During the workshop in Portland drafting team stated that the 3% and 3% allocation was the best compromise the members of the drafting team were able to agreed to. The data presented by the drafting team during the workshop did not support the statement that the amount of contingency reserves available in the WECC Interconnection will not decrease as a result of this new standard. We

believe that the reserve allocations should be based on the system studies rather then the ability of the drafting team to reach a compromise.

2. Requirement R.2. This requirement changes the definition of spinning reserve. Under this requirement the spinning reserve doesn't have to be carried by the synchronized generating units. The requirement states that spinning reserve needs to meet two requirements

R.2.1 Initially automatically respond to frequency deviations.

R.2.2. Capable of fully responding within ten minutes.

Based on this definition it is possible to use devices other generators to provide spinning reserves that could meet these requirements. The underfrequency relays for example could meet these new requirements, they will automatically respond to frequency deviation and will definitely respond within 10 minutes. We believe that this is a significant change in the definition of spinning reserves that again could have a detrimental effect on the stability of the WECC Interconnection.

3. R.3.6. This requirement identifies firm load as an acceptable type of reserves during energy emergency. This requirement does not specify if the load could only be used as a reserves by the BA declaring energy emergency. Based on the interpretation it is possible that every BA in the WECC or every BA in the Reserve Sharing Group could use firm load as a source of reserves once the energy emergency is declared by one single BA. This is also significant change from the previous standard and WECC MORC. The firm load was never before consider a source of reserves. I asked this question during the workshop and the drafting team did not provide an explanation why this was included as a acceptable source of contingency reserves.

We understand that there were many comments submitted to the drafting team during development process and we don't believe that all of these comments were addressed by the drafting team. We understand that there were some time limitations to develop and approve this standard, but we don't agree that this standard as currently written addresses all issues related to the contingency reserves in WECC Interconnection.

We believe that the above reasons were sufficient to justify our NO vote for this standard.

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Vicken Kasarjian, Sacramento Municipal Utility District (SMUD)

The following are the reasoning behind my “no” vote on VAR-002-WECC-1, BAL-002-WECC-1, FAC-501-WECC-1, TOP-007-WECC-1, and PRC-004-WECC-1.

General comments:

1. Unnecessary additional requirements for WECC Members with higher exposure to violations/sanctions. Without justification, WECC is trying to hold itself to higher standards than the rest of the nation under NERC.
2. The drafting teams did not actually test the proposed standards prior to bringing it to a vote. A 6 month test with some applicable entities would have been quite helpful.
3. No guidance on how to actually be compliant with these standards.

Additional specific comments:

1. BAL-002-WECC-1: 3% has no technical basis – should go with MSSC to retain or enhance reliability
2. FAC-501-WECC-1: Replaces WECC PRC-STD-005-1: Addresses maintenance and test requirements for additional components (CBs, reactive devices, transformers, etc) not addressed in PRC-005; this impacts Transmission Maintenance Inspection Program for the Major WECC Transfer Paths. Also, it uses a justification that states “minimize SOL reductions to maintain reliable Western Interconnection operation” – if this reasoning is true, then it should also be used by NERC.

****

John S. Forman, Transmission Agency of Northern California (TANC)

In response to the question of why a no vote was made on the standards at the OC meeting, TANC's OC representative voted no on five of the seven proposed standards for one basic reason: The standards require that the WECC be more stringent than the NERC standards. Those entities that have gone through an audit of the standards that are in effect are finding that they will be sited for something that is not in compliance. In other words, the auditors will keep looking until something is found to be wrong. With the WECC standards higher than NERC, even more compliance problems are anticipated. We believe that one basic instruction to the drafting teams should be that they need to justify a standard being more stringent than NERC, and that the basic draft should be no more than equal to NERC, unless it's clearly in the interest of the WECC. Our two positive votes on VAR-501 and IRO-006 are in that "best interest of WECC" category. The other standards were not. Basically, we are not sure that always being better than NERC is the right philosophy.

****

Board of Directors
April 16-18, 2008 **Voting Summary**
Coronado, CA **IRO-006-WECC-1**

Last Name	First Name	Organization	Class
Anderson	Bob	Non-affiliated Director	Non-Affiliated
Areghini	David	Salt River Project	Class 1
Barbash	Carolyn	Sierra Pacific Power Company	Class 1
Beyer	Lee	California Public Utilities Commission	Class 5
Brown	Duncan	Calpine Corporation	Class 3
Campbell	Ric	Utah Public Service Commission	Class 5
Cauchois	Scott	CADRA	Class 4
Chamberlain	Bill	California Energy Commission	Class 5
Cleary	Anne	Mirant Americas, Inc.	Class 3
Conway	Teresa	Powerex Corp.	Class 6
Coughlin	John	Non-affiliated Board Member	Non-Affiliated
Dearing	Bill	Grant County PUD	Class 2
Ferreira	Richard	TANC Executive Advisor	Class 2
Grantham-Richards	Maude	Farmington Electric Utility System	Class 2
Gutting	Scott	Energy Strategies, LLC	Class 4
Kelly	Nancy	Utah Committee of Consumer Services	Class 4
King	Jack	Non-affiliated Board Member	Non-Affiliated
LaFond	Steve	The Boeing Company	Class 4
Little	Doug	British Columbia Transmission Corporation	Class 6
McMaster	Dale	Alberta Electrical System Operator	Class 6
Moya	Jesus	Comision Federal de Electricidad	Mexico
Newton	Tim	Non-affiliated Director	Non-Affiliated
Sharpless	Jananne	Non Affiliated Board Member	Non-Affiliated
Smith	Marsha	Idaho Public Utilities Commission	Class 5
Stout	John	Mariner Consulting	Class 3
Tarplee	Gary	Southern California Edison	Class 1
Thuston	Tim	Williams Power	Class 3
Weis	Larry	Turlock Irrigation District	Class 2
VanZandt	Vicki	Bonneville Power Administration	Class 1
Zaozirny	Lori Ann	British Columbia Utilities Commission	Class 6

The Board Members listed above voted whether to approve IR0-006-WECC-1.
The Regional Reliability Standard was approved unanimiously.

UFAS STANDARD DRAFTING TEAM
WHITE PAPER

This paper discusses and attempts to clarify the DRAFT IRO-006-WECC-1 Standard posted for comment. The UFAS Standard Drafting Team (UFAS SDT) met on several occasions to draft a permanent replacement for IRO-STD-006-0 -- Qualified Path Unscheduled Flow Relief, which FERC approved on June 8, 2007.

Background:

On Friday June 8, 2007, the Federal Energy Regulatory Commission (FERC) issued an order approving the Western Electricity Coordinating Council (WECC) WECC-IRO-STD-006-0 (Qualified Path Unscheduled Flow Relief) Standard, which is one of the Tier 1 Regional Standards. This WECC Regional Reliability Standard was developed using WECC's Expedited Process for Urgent Action Interim Standards. The WECC Process requires that Interim Standards must have a termination date no longer than one year from the date of implementation. Interim Standards must be converted to permanent Standards or successor standards must be developed. The permanent/replacement standards must comply with the NERC requirements for Regional Reliability Standards including removal of the RMS Sanction Table and use of the NERC sanction table for enforcement purposes and address the directives in the June 8, 2007 FERC order.

The Triage Committee (Standards Request Routing Committee) identified the WECC Operating Committee (OC) as the lead Standing Committee for the Tier One Standards, and the OC has assigned the Unscheduled Flow Administrative Subcommittee (UFAS) to take the lead on project WECC-0024/Unscheduled Flow Relief developing a permanent/replacement Regional Reliability Standard. A standards drafting team (SDT) was formed for project WECC-0024/Unscheduled Flow Relief. Upon approval by FERC, WECC Regional Reliability Standards become part of the body of the NERC Reliability Standards and will be enforced through monetary sanctions in the United States. The SDT is posting a draft standard for comment on the WECC website.

The UFAS SDT reviewed the recently approved standard and considered all comments received, including comments submitted by FERC and NERC. The SDT discussed several approaches to the task. During discussions, several aspects of the current plan were discussed and recommendations were made to modify the standard to make it more effective at mitigating Unscheduled Flow and enhance the reliable operation of the Western Interconnection. Results of a straw poll taken at the June, 2007 WECC OC and MIC meetings indicated support for a shift of responsibility in the Contributing Schedule curtailment portion of unscheduled flow mitigation. As a result, the SDT decided to implement a change in responsibility for initiating schedule curtailments.

Qualified Path Unscheduled Flow Relief Criterion in RMS and IRO-STD-006-0:

The Qualified Path Unscheduled Flow Relief responsibilities do not conform to the current NERC functional model. This RMS Criterion and currently-approved standard assigns Load Serving Entities (LSE's) the responsibility of curtailing schedules to reduce unscheduled flow, a reliability function that the NERC functional model now assigns to Reliability Coordinators and Balancing Authorities. In the functional model, NERC holds that LSEs should not be assigned responsibility for reliability. Therefore, the assignment of reliability functions to LSEs is not compatible with the NERC functional model or NERC Standard IRO-006. Additionally, the existing RMS and IRO-STD-006 standards place the sole responsibility for providing relief upon the LSE without providing the ability for the LSE to ensure compliance (e.g. the Balancing Authority does not have to approve a curtailment request made by the LSE). The LSE through the webSAS program emulates a Reliability Coordinator. With the WebSAS tool, the LSE can only enter a curtailment, but this curtailment may be denied by a Balancing Authority. The LSE cannot ensure implementation of the requested reliability curtailments. When IRO-STD-006 was approved, FERC directed WECC to address these concerns in developing a permanent replacement reliability standard. (See paragraphs 71 and 72 in the FERC Order in Docket RR07-11-000.) For these reasons, the drafting team recommends that LSEs should not be assigned reliability functions such as curtailments. In the proposed IRO-006-WECC-1 standard, responsibility for initiating schedule curtailment is assigned to the Reliability Coordinators, and the responsibility for implementing the curtailments is assigned to Balancing Authorities. The proposed standard should improve the efficiency of the program including improved compliance, more certain Unscheduled Flow relief, and fewer complications associated with multiple entities taking partial responsibility for curtailment activity.

Explanation of the Standard:

The SDT essentially boiled the standard down to two Requirements and two Measures:

Explanation of REQUIREMENT 1:
Once the Transmission Operator calls upon the UFMP at a level that requires some degree of off-path tag curtailments, the Transmission Operator notifies its corresponding Reliability Coordinator (RC) that it is requesting Contributing Schedule curtailments. Upon determining the request is appropriate, the RC must utilize the webSAS software to initiate the required tag curtailments. Curtailments are envisioned to be based upon either the exact prescription of curtailments specified in the table of curtailment actions of the Unscheduled Flow Mitigation Plan (UFMP) or upon the order of highest transfer distribution factor tags curtailed first—a pre-selection of preferred option may be made by each Load Serving Entity. This means that the Unscheduled Flow Mitigation Plan (UFMP) will be administered just as it is today with the exception that, instead of over one hundred LSEs determining which tags to curtail, a single RC shall initiate schedule curtailments with a single command for all entities through the webSAS software.

Explanation of REQUIREMENT 2:
Once the Source and Sink Balancing Authorities receive Curtailment requests through their tagging systems, the Balancing Authorities' must actively approve the curtailment request; implement alternative actions that provide the Relief Requirement; or a combination thereof that collectively meets the Relief Requirement. This requirement does not change any part of the UFMP as today Balancing Authorities should actively approve all curtailment requests.

Explanation of MEASURE 1:
Requirement 1 is considered to be met if any RC in any of the Reliability Centers sends the command to initiate curtailments using the webSAS tool. The final state of the tags with pending curtailment requests are not at issue. The measure merely assures that the RC initiates the curtailment process.

Explanation of MEASURE 2:
Requirement 2 is considered to be met if each Sink Balancing Authority who has authority to approve or deny the curtailment requests, in fact, approves the curtailment requests or provides alternative action such as generation redispatch, phase-shifter operation, DC circulation, or some combination thereof. If the Balancing Authority does not implement a requested curtailment or alternative actions are not implemented, then Requirement 2 has not been met.

Discussion:

It is the intent of the UFAS SDT that the UFMP shall continue to be the WECC plan to mitigate Qualified Path unscheduled flow in the Western Interconnection and that the Plan continues to be implemented exactly as it is today with the one exception that the LSE no longer initiates the curtailments to their own tags. The reasons for this are several:

1. Most LSEs do not enjoy the level of choice as to which tags to curtail as had been envisioned when the webSAS tool was implemented,
2. LSEs who are not WECC members do not take the opportunity to register and, as a result, avoid the responsibility for the curtailments; this responsibility then defaults to the Sink Balancing Authority to initiate the cuts, putting the Balancing Authorities at an increased risk for incurring a violation,
3. LSEs have no control over whether the curtailments that they request are approved. The Standard now only requires that the responsible party – the RCs initiate a curtailment,
4. LSEs may retain some choice in determining which curtailments are enacted as UFAS intends to modify the webSAS tool to permit LSEs the option to select either (1) curtailments from highest Transfer Distribution Factors to lowest until compliance is reached, or (2) select curtailments of all contributing schedules as prescribed by the table of curtailment actions in the UFMP, with the latter as the default choice.

It is not the intent of the UFAS SDT to burden the RCs. Today when a Transmission Operator requests a step 4 or above curtailment, the RC is usually involved in making the decision since it is responsible for reliability. Requiring the RC to initiate the curtailment process allows the RC the opportunity to assess the request and override the request if necessary. If the RC takes no action, it is expected that the webSAS software will initiate curtailments automatically. This process will also minimize any further Balancing Authority action regarding curtailments.

The refinements implemented through the proposed IRO-006-WECC-1 standard should

1. Result in consistent curtailments at the proper level,
2. Remove the lack of action as an impediment to achieving the proper curtailments,
3. Relieve the LSEs of the burden of deciding which action should be taken, allowing them to spend their time initiating the scheduling of energy to replace that curtailment with schedules that either relieve the constrained path or are impact neutral,
4. Place the control of reliability actions back with reliability-trained personnel, and
5. Significantly reduce compliance auditing for LSEs and WECC Staff to determine compliance with the plan.

The USF SDT includes representatives from the RCs, Constrained Path Transmission Operators, and LSEs. The proposed standard has included input from these parties. We believe the proposed standard satisfies their concerns and has their support.

Members of the drafting team have held discussions with the webSAS vendor and believe the necessary software modifications to ensure implementation of this standard can be satisfied without undue burden on any party.

The USF SDT requests that your organization support the refinements to UFMP and recognize that the proposed standard improves the efficiency of the plan and more importantly, reliable operation of the Interconnection.

Recommendations from Corporate Governance and Human Resources Committee on Standards Process

Board Action Required

Approve the following resolutions implementing the recommendations of the Corporate Governance and Human Resources Committee in partial response to the board's mandate to review certain aspects of NERC's reliability standards process, and discuss one issue on which the committee has not yet reached a recommendation.

Information

Issue Summaries are attached supporting the recommendations for Issue 4.a (**Attachment A**) and Issue 5 (**Attachment B**).

Items for Board Action

Issue 4.a — *What should be NERC's process for developing standards in national security emergency situations, especially for cyber security?*

CGHR Recommendations:

- Issue Essential Actions (Alerts) to address national security issues of immediate concern in advance of the development of standards.
- Develop cyber or physical security standards, as needed, on an expedited and confidential basis, as described in the attached "*Proposed Process for Developing Essential Action Alerts and Reliability Standards to Address National Security Emergency Situations*," (**Exhibit 4.a.i**).

Proposed Board Resolution:

WHEREAS, it may be necessary in certain national security emergency situations for NERC to develop Essential Action Alerts and Reliability Standards on an expedited and confidential basis using a process that varies somewhat from the NERC *Reliability Standards Development Procedure*; and

WHEREAS, the Corporate Governance and Human Resources Committee of the NERC Board of Trustees, after due consideration of several options and input from the stakeholder community, has recommended that NERC issue Essential Actions (Alerts) to address national security issues of immediate concern in advance of the development of standards; and that NERC develop cyber or physical security standards, as needed, on an expedited and confidential basis, as described in the attached "*Proposed Process for Developing Essential Action Alerts and Reliability Standards to Address National Security Emergency Situations*," (**Exhibit 4.a.i**);

RESOLVED, that the NERC Board of Trustees endorses the recommendations of the Corporate Governance and Human Resources Committee and directs NERC management to take the steps necessary to implement the committee's recommendations, including appropriate modification of the NERC Rules of Procedure, Reliability Standards Development Procedure, or any other NERC documents.

Issue 5.1 — *How should NERC manage FERC staff participation in Standards Drafting Team activities while maintaining adherence to ANSI principles?*

CGHR Recommendation:

- Allow FERC staff to participate in all standards drafting team activities in accordance with the *NERC Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities* (**Exhibit 5.a**).

Issue 5.2 — *How should NERC manage FERC staff verbal feedback not associated with directives in an Order?*

CGHR Recommendation:

- Respond to FERC staff's verbal comments as the team would consider comments offered by other participants in the team setting in accordance with the *NERC Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities* (**Exhibit 5.a**).

Proposed Board Resolution:

WHEREAS, NERC has not established formal policies or provided guidance to its standards drafting teams regarding FERC staff involvement in standard drafting team activities while maintaining adherence to the principle of openness; and

WHEREAS, NERC has not established formal policies or provided guidance to its standards drafting teams regarding how teams should respond to FERC staff comments on draft standards not associated with FERC directives in an Order; and

WHEREAS, the Corporate Governance and Human Resources Committee of the NERC Board of Trustees, after due consideration of several options and input from the stakeholder community, has recommended: (1) that NERC allow FERC staff to participate in all standards drafting team activities and (2) that standards drafting teams respond to FERC staff's verbal comments as the team would consider comments offered by other participants in the team setting, as described in the proposed *NERC Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities* (**Exhibit 5.a**);

RESOLVED, that the NERC Board of Trustees endorses the recommended *Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities* and directs NERC management to take the steps necessary to communicate to and implement this guidance with FERC staff, NERC staff, NERC Standards Committee, and all NERC standards drafting teams.

Item for Board Discussion

Issue 1.a — *How should the Violation Risk Factors and Violation Severity Levels associated with Reliability Standards be developed and approved?*

The committee has had extensive discussion and stakeholder input on this issue on two conference calls, but has not yet agreed on a recommendation to the board. Committee chairman, John Anderson, will lead this discussion.

Background

At its May 7, 2008 meeting, the board gave a mandate to its Corporate Governance and Human Resources Committee to review the NERC standards development process policies, procedures, and priorities and specifically to address the following:

1. To Determine How NERC Should Handle the Violation Severity Level and Violation Risk Factor Compliance Elements (Short Term)
2. To Review the Opportunities to Further Prioritize the Standards Workload (Longer Term)
3. To Reexamine the Process by Which NERC Establishes Reliability Standards Under Normal Circumstances (Longer Term)
4. To Reexamine the Process by Which NERC Establishes Reliability Standards Under Urgent Action Circumstances, Especially for Cyber Security (Short Term)
5. To Reexamine NERC's Relationship with FERC Regarding the Reliability Standards Approval Process (Longer Term)
6. To Review Overall Stakeholder Participation in the Reliability Standards Approval Process (Longer Term)

The complete mandate is attached. (**Attachment C**)

Committee Work Plan and Timeline

The objective of the work plan is to address both the short-term and longer-term issues as described in the mandate as soon as possible, and bring recommendations to the board as soon as they are ready.

The committee will seek input on the issues in its mandate from others, including the NERC Director of Standards, the current and past chairs of the Standards Committee, and the Regional Entity Management Group liaison. The NERC staff coordinator for this mandate will facilitate the committee's activities and the development of its recommendations to the NERC board.

Short-Term Issues — those that pertain directly to the compliance elements of NERC Reliability Standards, namely Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), and the development of standards under urgent action circumstances (Issues 1 and 4 of the mandate.)

Longer-Term Issues — include, but are not limited to, the remaining issues identified in the mandate (Issues 2, 3, 5, and 6.) In particular, the committee will consider how other regulatory and self-regulatory organizations (e.g., Financial Industry Regulatory Authority and Nuclear Regulatory Commission) develop standards and promote compliance with them through compliance tools and assistance programs, regulatory guides, bulletins, generic letters, etc.

The committee will also discuss how to improve communication and coordination between the Standards and Compliance programs.

Members of the Committee and Others Involved for this Mandate

John Q. Anderson, Committee Chairman
Thomas W. Berry, Committee Member
Janice B. Case, Committee Member
Sharon L. Nelson, Committee Member
Richard Drouin, Ex-Officio Committee Member
Rick Sergel, Ex-Officio Committee Member

David R. Nevius, NERC Senior Vice President (Staff Coordinator for this Mandate)
Gerard Adamski, NERC Vice President and Director of Standards
R. Scott Henry, Chairman, NERC Standards Committee
Linda Campbell, Co-Chair, NERC Standards Committee Process Subcommittee (Past Chair of Standards Committee)
Gerry W. Cauley, SERC President & CEO (Regional Entity Management Group Liaison)

Attachment A

ISSUE 4.a
DEVELOPING STANDARDS IN NATIONAL SECURITY EMERGENCY SITUATIONS

I. ISSUE: What should be NERC's process for developing standards in national security emergency situations, especially for cyber security?

II. RECOMMENDATION: Option 5

Issue Essential Actions (Alerts) to address national security issues of immediate concern in advance of the development of standards.

Develop cyber or physical security standards, as needed, on an expedited and confidential basis, as described in the attached "*Proposed Process for Developing Essential Action Alerts and Reliability Standards to Address National Security Emergency Situations,*" (**Exhibit 4.a-1**).

III. BACKGROUND:

The question posed in the mandate was: "Should the NERC board review ways to improve and expedite the standards process for urgent matters including moving to a model similar to other self-regulatory organizations[1] where a group of subject matter experts (and/or organization staff) draft the standards, post the standards for comment, consider the comments, seek approval to file the standards with the appropriate government agency, and file the standards? (In such a process the stakeholders have at least two opportunities for input; once with the standard as it is being developed and again when it is filed with the regulatory agency. In such a process, there is no vote by the stakeholders.)"

The NERC standards development process includes provisions for expediting the development of reliability standards under Urgent Action or Emergency conditions, and the Rules of Procedure include a section on Directives to Develop Standards under Extraordinary Circumstances, as described below.

Urgent Action

"Under certain conditions, the Standards Committee may designate a proposed standard or revision to a standard as requiring urgent action. Urgent action may be appropriate when a delay in implementing a proposed standard or revision can materially impact the reliability or security of the bulk power systems or be inconsistent with statutory or regulatory requirements for reliability standards, such as by causing adverse impacts on markets or undue discrimination. The Standards Committee must use its judgment carefully to ensure an urgent action is truly necessary and not simply an expedient way to change or implement a standard."

"A requester prepares a SAR and a draft of the proposed standard and submits both to the standards process manager. The SAR must include a justification for urgent action. The standards process manager submits the request to the Standards Committee for its consideration. If the Standards Committee designates the requested standard or revision as an urgent action item, then the standards process manager shall immediately seek

[1] FINRA is one such model to consider. FINRA staff draft the standard, post it for comment, consider the comments and submit a final proposed standard to the SEC. The SEC also posts it for comment and then issues its order approving the final standard.

participants for a ballot pool (as described in Step 3 of the process) and shall post the pre-ballot draft. This posting requires a minimum 30-day posting period before the ballot and applies the same voting procedure as described in Step 9."

Emergency Action
"After making a written finding that an extraordinary and immediate threat exists to bulk power system reliability or National security, the NERC board shall have the discretion to take the following emergency actions to further expedite the urgent action procedure described above:

- Reduce or suspend the 30-day pre-ballot review of a proposed emergency standard.
- Reduce the time period for voting by stakeholders to 5 days for the initial ballot, and if necessary 5 days for the recirculation ballot."

"If a standard is adopted through an urgent or emergency action, one of the following three actions must occur:

- If the urgent or emergency action standard is to be made permanent without substantive changes, then the standard must proceed through the regular standards development process to be balloted by stakeholders within one year of the urgent or emergency action approval by stakeholders.
- If the urgent or emergency action standard is to be substantively revised or replaced by a new standard, then a request for the new or revised standard must be initiated as soon as practical after the urgent or emergency action ballot and the standard must proceed through the regular standards development process to be balloted by stakeholders as soon as practical within two years of the urgent or emergency action approval by stakeholders.

The urgent or emergency action standard may be withdrawn through the regular process by a ballot of the stakeholders within two years."

Directives to Develop Standards under Extraordinary Circumstances
Section 309.3 of the NERC Rules of Procedure states:

"An ERO governmental authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a reliability standard. In such a case, the applicable agency may direct the development of a standard within a certain deadline. NERC staff shall prepare the standards authorization request and seek a stakeholder sponsor for the request. If NERC is unable to find a sponsor for the proposed standard, NERC will be designated as the requestor. The proposed standard will then proceed through the standards development process, using the urgent or emergency action procedures described in the *Reliability Standards Development Procedure* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards."

"Consistent with all reliability standards developed under the urgent or emergency action process, each of the three possible follow-up actions as documented in the *Reliability Standards Development Procedure* are to be completed through the standards development process and are subject to approval by the ERO governmental authorities in the U.S. and Canada."

NERC Alerts
In addition, NERC has the ability, through its Alerts program, to issue Recommendations or Essential Actions as described in its Rules of Procedure section 810, as described below.

"When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions.

> **Level 1 (Advisories)** – purely informational, intended to advise certain segments of the owners, operators and users of the bulk power system of findings and lessons learned;
>
> **Level 2 (Recommendations)** – specific actions that NERC is recommending be considered on a particular topic by certain segments of owners, operators, and users of the bulk power system according to each entity's facts and circumstances;
>
> **Level 3 (Essential Actions)** – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the bulk power system to take to ensure the reliability of the bulk power system. Such Essential Actions require NERC board approval before issuance.

"The bulk power system owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such bulk power system owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC."

"NERC will advise the Commission and other applicable governmental authorities of its intent to issue all Level 1 Advisories, Level 2 Recommendations, and Level 3 Essential Actions at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other applicable governmental authorities no later than thirty (30) days following the date by which NERC has requested the bulk power system owners, operators, and users to which a Level 2 Recommendation or Level 3 Essential Action issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other applicable governmental authorities will describe the actions taken by the relevant owners, operators, and users of the bulk power system and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for confidential or critical infrastructure information."

In both cases, entities to which the Recommendations or Essential Actions apply are required to provide reports to NERC of actions taken and timely updates on progress towards resolving the issues raised. Failure to respond is not a standards violation but rather non compliance with the Rules of Procedure, which constitutes a violation of the provisions of the Federal Power Act in the U.S. (It is unclear at this point what would be the nature of the consequences in each of the Canadian provinces for failure to comply with the Rules of Procedure.)

Draft Cyber Legislation
FERC staff developed draft cyber/reliability authority legislation that proposed to give FERC the authority, on its own motion, with or without notice, hearing, or report, to order

emergency actions to protect the bulk power system against an imminent cyber security or other national security threat whenever the President or a national security agency or national intelligence agency of the U.S. government issues a written directive or determination that an imminent cyber security or other national security threat exists. It appears that this proposed legislation will not be acted on during this session of Congress.

IV. <u>OPTIONS AND ANALYSIS</u>:

The pros and cons of each option are discussed below:

Option 1: Continue to use the Urgent Action or Emergency provisions of the NERC *Reliability Standards Development Procedure* to develop standards under national security emergency circumstances, including cyber security standards. **[Status Quo]**

PROS: Process is already well defined.

Process is open and transparent and allows stakeholder input and voting in the development of such standards.

CONS: Could result in unmitigated reliability gap as the process still takes some time to develop, approve, and implement standard. (Several months to one year.)

Process is open and transparent, which may not be desirable in cases of a security standard that is needed based on a national security threat.

Enforceability of Recommendations or Essential Actions via NERC's Rules of Procedure is not well-defined or understood by industry.

Option 2: In cases of a declared national security emergency, develop security standards on an expedited and confidential basis outside of the Urgent Action or Emergency procedures of the *Reliability Standards Development Procedure* or the procedures in Section 309.3 of the Rules of Procedure, as described in the attached "*Proposed Process for Developing Essential Action Alerts and Reliability Standards to Address National Security Emergency Situations,*" (**Exhibit 4.a-1**)

PROS: Shortens the time for development of standards needed on an emergency basis.

Permits a more expedient mitigation of a reliability gap.

Avoids public disclosure of security vulnerabilities.

CONS: Limits stakeholder involvement in the development and approval process, which could lead to lack of industry support and possible challenges during compliance enforcement proceedings.

Process does not satisfy ANSI requirements for accreditation and demonstrated industry consensus.

Option 3: Allow FERC to develop cyber security standards, as proposed in draft legislation.

PROS: Avoids FERC criticism of the NERC process being too slow or coming up standards that FERC judges to be inadequate.

CONS: Limits stakeholder involvement in the development and approval process, which could lead to lack of industry support and possible challenges during compliance enforcement proceedings.

Does not recognize the need for Canadian involvement in the development and implementation of these standards.

Canadian entities would not be subject to FERC standards.

Option 4: Issue Recommendation or Essential Action (Alerts) to address security issues of immediate concern in advance of the development of standards, regardless of which process is used for standards development.[2]

PROS: Immediately addresses any reliability gap while standards are being developed.

Avoids FERC criticism of the NERC process being too slow in addressing a national security issue.

Allows flexibility in developing interim or permanent standards through any of the established standards development processes.

Compatible with any additional authority given to a U.S. government agency through legislation or other means.

Could be adopted as an interim solution in conjunction with Options 1, 2, or 3.

CONS: Relies on the Federal Power Act for enforcement of non compliance with Recommendation or Essential Action Alerts prior to the development of an enforceable standard.

No provision exists at this time in any Canadian jurisdiction for enforcement of non compliance with Recommendations and Essential Actions.

Option 5: Issue Essential Actions (Alerts) to address national security issues of immediate concern in advance of the development of standards.

Develop cyber or physical security standards, as needed, on an expedited and confidential basis, as described in the attached "*Proposed Process for Developing Essential Action Alerts and Reliability Standards to Address National Security Emergency Situations,*" (**Exhibit 4.a-1**).

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[2] Where necessary, these Recommendation or Essential Action Alerts would be issued as CONFIDENTIAL Alerts to avoid having them reveal the nature of the threat or vulnerability to other than those registered entities to whom the Alert is directed.

PROS: Immediately addresses any reliability gap while standards are being developed.

Avoids FERC criticism of the NERC process being too slow in addressing a cyber or physical security reliability issue.

Allows flexibility in developing interim or permanent standards through any of the established standards development processes.

Does not require federal legislation.

Allows input by affected stakeholders.

Would be applicable in the U.S. and Canada.

Compatible with any additional authority given to a U.S. government agency through legislation or other means.

CONS: Relies on the Federal Power Act for enforcement of non compliance with an Essential Actions Alert prior to the development and implementation of an enforceable reliability standard.

No provision exists at this time in any Canadian jurisdiction for enforcement of non compliance with Essential Action Alerts.

Exhibit 4.a.i

Proposed Process for Developing Essential Action Alerts and Reliability Standards to Address National Security Emergency Situations

It may be necessary in certain national security emergency situations for the ERO to develop Essential Action Alerts and Reliability Standards on an expedited and confidential basis using a process that varies somewhat from the NERC *Reliability Standards Development Procedure*.

In general, the threshold for invoking such a special process will be:

> The President of the U.S. or Prime Minister of Canada or a national security agency or national intelligence agency of either or both governments issues to the ERO a written directive or determination that an imminent national security threat to the reliability of the bulk power system exists.

Essential Action Alerts

Upon receiving such directive or determination, the NERC board[3] will direct the immediate development and issuance of an Essential Action Alert to those registered entities that are the subject of the Alert, with a response required by a given date.[4]

NERC will establish and draw on a standing body of experts to assist in the development of such Alerts, which experts will all have pre-confirmed security credentials on file with NERC that are appropriate to the task at hand.[5]

Reliability Standards

The board may also direct the immediate development of a new or revised reliability standard to address the national security emergency situation using one of two processes.

If circumstances allow, NERC will use one of the provisions of its open and transparent *Reliability Standards Development Procedure* – Normal Action, Urgent Action, or Emergency Action.

If the nature of the threat or vulnerability that necessitated the national security directive demands confidentiality, NERC will utilize the following process to develop a reliability standard:

1. Assemble a special drafting team from an established pool of subject matter experts who all have pre-confirmed security credentials appropriate to the task at hand and pre-signed confidentiality agreements on file with NERC.
2. The team will draft the reliability standard to address the national security emergency based on the threat information (rationale and justification) provided by government agencies, their own knowledge and expertise, and input from other government sources; e.g., national laboratories.

---

[3] NERC will evaluate the need for security clearances for NERC board members to engage in this process and make appropriate revisions to its Rules of Procedure to govern the process the NERC board will use in making determinations to issue Essential Action Alerts in cases of national security emergencies.

[4] Depending on the nature or subject matter of the Essential Action Alert, NERC may restrict its distribution to individuals within registered entity organizations who possess certain security credentials appropriate to the situation.

[5] It is anticipated that the individuals that comprise the standing body or pool of subject matter experts that NERC could call on to assist in the development of Essential Action Alerts or Security Standards would enter into “nuclear safeguards-like” information protection agreements and potentially government supported background checks.

3. The team will discuss the draft standard, as it is being developed, with officials from the appropriate governmental agencies in the U.S. and Canada, under strict security and confidentiality rules.
4. The team will distribute the draft standard for comment, under strict confidentiality rules (NDA or nuclear safeguards like), only to those entities that will be expected to comply and who have identified individuals from their organizations that adhere to the confidentiality requirements. These individuals will not be required to have security clearances to review and comment on the proposed standard, but must have signed confidentiality agreements with NERC.[6]
5. Following any adjustments to the draft standard based on comments received in Steps 3 and 4, the team will request approval by ballot of a normal standard ballot pool formed for this purpose. Only the proposed standard will be posted for ballot, as the information supporting the need for the standard will need to remain confidential.
6. Upon receiving the required 2/3 weighted-segment vote approving the standard, and the subsequent recirculation ballot, the team will present the proposed standard to the NERC board for approval in a special closed session, either in person or by conference call. (The closed session will allow the team to present not only the standard, but also the confidential information supporting its need.)
7. Following approval by the board, the standard will be filed with the FERC and with the appropriate governmental authorities in Canada for immediate action and implementation.
8. Following governmental approvals, the standard will be noticed to those registered entities for which compliance is required and posted on the NERC website.
9. Compliance monitoring and enforcement will be undertaken based on the effective date of the standard. Special procedures may be used in monitoring and enforcing compliance to ensure that no information is made public that could increase the vulnerability of the threat for which the standard was developed.

[6] In this phase of the process, only the proposed standard will be distributed to those entities expected to comply, not the rationale and justification for the standard. Only the special drafting team members, who have the appropriate security credentials, will have access to this rationale and justification.

ISSUE 5
FERC STAFF ROLE IN STANDARDS DEVELOPMENT

I. ISSUE: What should be FERC staff's role in the Reliability Standards Development Process?

II. RECOMMENDATIONS:

POLICY QUESTION 1: *How should NERC manage FERC staff participation in Standards Drafting Team activities while maintaining adherence to ANSI principles?*

RECOMMENDATION: Allow FERC staff to participate in all standards drafting team activities in accordance with the *NERC Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities* (**Exhibit 5-1**).

POLICY QUESTION 2: *How should NERC manage FERC staff verbal feedback not associated with directives in an Order?*

RECOMMENDATION: Respond to FERC staff's verbal comments as the team would consider comments offered by other participants in the team setting in accordance with the *NERC Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities* (**Exhibit 5-1**).

III. BACKGROUND:

Questions Included in the Mandate

Define policy for FERC staff involvement in standard drafting team activities. Define the policy for how drafting teams should respond to FERC staff comments not associated with an order or directive. FERC staff has refrained from formally submitting these comments in accord with the ANSI process and has provided these comments verbally. The question is how to reconcile NERC's principle that drafting team meetings be open and discussions documented versus FERC staff's desire to provide input outside the drafting team meetings.

History

August, 2005 – "The ERO should consult with the appropriate authorities in each country with regard to reliability standards under development, to minimize the likelihood of a remand being exercised." *("Principles for an Electric Reliability Organization That Can Function on an International Basis")*

August, 2005 - "The Commission shall give due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard or modification to a reliability standard [emphasis added] and to the technical expertise of a regional entity organized on an Interconnection-wide basis with respect to a reliability standard to be applicable within that Interconnection, but shall not defer with respect to the effect of a standard on competition." (Section 215 of the *Federal Power Act*)

December, 2006 – NERC submits its *Reliability Standards Development Plan: 2007-2009* to FERC on an informational basis. This three-year work plan identifies the projects involving NERC reliability standards that will be undertaken to clean up Version 0 standards and address FERC directives and considerations offered in the FERC staff

May 11, 2006 report and in the Commission's NOPR on NERC's request for approval of its reliability standards.

March, 2007 – The Commission issues the Final Standards Rule, Order No. 693, that approved 83 of 107 reliability standards proposed, held 24 pending further information, and directed further revisions to 56 standards. In the Order, the Commission also opined on their directives in general and how the ERO should treat them.

Spring, 2007 – NERC and FERC staff discuss standards development activities and invite FERC staff participation in drafting team activities as a means to effectively identify and resolve concerns. The expected benefits include an opportunity for NERC to understand staff concerns while drafting teams are in the process of developing the standards such that these concerns could be considered by the team. Initially, communications on standards-related concerns were FERC to NERC staff without drafting team members included.

April, 2007 – NERC issues "Guidance to Standards Drafting Teams Relative to FERC Order Nos. 693 and 890" (attached), whose purpose is to "provide guidance to the standards teams on how to appropriately consider and respond to the Commission's directives in the context of the standards development process. Additional clarity is also provided regarding Commission staff's involvement in the standards drafting teams."

June, 2007 – NERC staff and members of the Relay Loadability standard drafting team discussed the proposed standard with FERC staff that addresses, in part, a key blackout recommendation. FERC staff refrained from offering written comments during an open comment period and as these comments were not supported by a FERC directive, the drafting team was not clear on how they should be considered. The Standards Committee instructed that if the team considered the comments and elected to make any changes to the standard as a result, they should post the proposed changes for industry review in another comment period with the team's understanding of FERC staff concerns.

Summer, 2007 – FERC-NERC communication on standards activities modified to include key members of the drafting team and a tiered approach discussed that would include higher level staff involvement from NERC and FERC for unresolved issues. FERC staff continues to refrain from offering written comments during the open industry comment periods per the ANSI process. These meetings are viewed as most beneficial by NERC staff and drafting team members when the drafting teams propose the first draft of a new or modified standard and after receiving industry feedback through a comment period, and then again when the team is nearly completed its final draft of the proposed standard.

October 5, 2007 - NERC submits its updated *Reliability Standards Development Plan: 2008-2010* to FERC on an informational basis.

Fall, 2007 – Project 2006-01 - Personnel Training. Standard Drafting Team embroiled in controversial discussions with FERC staff and NERC staff person regarding the perceived deficiencies in the team's approach in addressing FERC Order No. 693 directives. NERC staff posited that the team did not completely address the Commission directives and offered no technical justification for doing so; therefore, the NERC staff could not support the drafting team's request for posting of the revised version for industry comment. Standards Committee engaged to provide guidance that ultimately resulted in a meeting with FERC staff that included representatives from the drafting team, NERC staff, and the Standards Committee chair and vice-chair.

February, 2008 - Member Representatives Committee – Presentation/discussion regarding NERC staff's "heavy-handedness" with respect to the training team, and FERC's observations on the deficiencies with proposed reliability standards on training and on relay loadability that was to be presented to the Board for approval the next day. FERC staff also reinforced the benefit of pre-filing meetings to discuss standards to be filed for Commission approval,

Spring-Summer 2008 – NERC staff, members of the Standards Committee, and regional entity representatives participated in individual meetings with seven Canadian provincial regulators (National Energy Board, British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, and Quebec). Unanimous concern expressed by Canadians regarding FERC staff's role in standards development activities. The general viewpoint expressed is that Canadian regulators do not directly engage in the development process for those items the regulators may ultimately have to act upon, such as reliability standards. Rather, they defer to the entities they have designated for reliability within their jurisdiction to provide technical input within the confines on NERC's ANSI-accredited standards development process. Hence, they support in theory and practice the self-regulatory ERO model envisioned by the bilateral ERO group and question FERC's commitment to this model. One salient comment from a Canadian regulator provides a good summary, "FERC does not want to regulate, they want to co-manage."

April, 2008 – In an attempt to better clarify the roles and responsibilities of all standard drafting team participants, especially FERC staff and NERC staff, NERC staff drafted "Roles and Responsibilities: Standards Drafting Team Activities" for comment. Similar to the feedback documented above, significant concerns were expressed from the Canadian entities and regulators over FERC staff's role in the process (*see letter from Canadian Electricity Association*), and by U.S. entities on FERC staff's refusal to document in writing the comments and concerns they offer to the drafting teams verbally and outside of the ANSI process.

May, 2008 - Member Representatives Committee – continued discussion on NERC staff and FERC staff role in standards development.

May, 2008 – Board of Trustees Meeting – Corporate Governance and Human Resources Committee assigned responsibility to review the issues raised regarding concerns in the standards development process.

Observations/Considerations

- Concern over FERC staff involvement seems to be more an issue with teams established before 2007.
- Per ANSI process and NERC Rules of Procedure, all standard drafting team meetings are open to those who wish to participate.
- FERC staff involvement has generally been beneficial to the standard drafting efforts with notable exceptions as outlined above. Particularly in pre-filing discussions, FERC staff discussion on a proposed standard points to the areas NERC staff needs to focus on in its formal filing and gives some insight into what questions might appear in the NOPR. Further, the drafting teams have been able to gain further clarity from FERC staff around the intent of directives in the Orders. Some feel, however, that all further guidance from FERC resulting from its directives should be managed in a formal documented manner.
- FERC staff does not speak for the Commission. Comments offered by FERC staff can be related to a directive or a consideration in an Order, or a technical opinion on a certain matter not related to an Order. The drafting teams have difficulty distinguishing between the two.

- The team's reception to FERC staff participation is based on the level of expertise the staff person brings to the table. The dynamics of standard drafting team meetings is often altered with FERC staff present at the meetings, especially if the staff person says little and takes a lot of notes.

Overarching Policy Questions

1. How should NERC manage FERC staff participation in Standards Drafting Team activities while maintaining adherence to ANSI principles?

2. How should NERC manage FERC staff verbal feedback not associated with directives in an Order?

IV. OPTIONS AND ANALYSIS:

The pros and cons of each option are discussed below for each of the two policy questions:

POLICY QUESTION 1:
How should NERC manage FERC staff participation in Standards Drafting Team activities while maintaining adherence to ANSI principles?

Option 1: Allow FERC staff to participate in all standards drafting team activities in accordance with the *NERC Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities* (**Exhibit 5-1**).

PROS: Most efficient as it permits FERC staff views on the content and wording of standards to be aired early in the development process.

Consistent with ANSI principles and ERO Rules of Procedure.

Permits a view to the issues that may likely appear in a formal FERC NOPR or Order.

Permits FERC staff to understand and appreciate the context and complexity of the issues the drafting team is attempting to resolve relative to a new standard.

Supports the concept of "no surprises" in the filing of proposed standards.

CONS: Having a regulatory staff person participating actively in the standards development process is contrary to the role that is allowed for regulators in Canada, thereby creating the appearance of a double standard.

FERC staff opinion potentially receives more weight than other participants and may bias the development process.

Option 2: Allow FERC staff to only observe standards drafting team meetings.

PROS: Permits FERC staff to understand and appreciate the context and complexity of the issues the drafting team is attempting to resolve relative to a new standard.

Avoids the perception that FERC staff is unduly influencing the standards development process.

Puts FERC staff and the regulatory staff from government authorities in Canada on an equal footing.

CONS: Not efficient as it does not permit FERC staff views on the content and wording of standards until a separate meeting is arranged between FERC staff, NERC staff, and key drafting team participants.

May not be sufficient involvement from a FERC perspective.

Violates ANSI principles and ERO Rules of Procedure.

Option 3: Do not allow FERC staff to attend any standards drafting team meetings.

PROS: Avoids any perception that FERC staff is unduly influencing the standards development process.

Puts FERC staff and the regulatory staff from government authorities in Canada on an equal footing.

CONS: Likely not acceptable to FERC.

Violates ANSI principles and ERO Rules of Procedure.

Not efficient as it does not permit FERC staff to understand and appreciate the context and complexity of the issues the drafting team is attempting to resolve relative to a new standard until a separate meeting is arranged for FERC staff, NERC staff, and key drafting team participants.

POLICY QUESTION 2:
How should NERC manage FERC staff verbal feedback not associated with directives in an Order?

Option 1: Respond to FERC staff's verbal comments as the team would consider comments offered by other participants in the team setting in accordance with the *NERC Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities* (**Exhibit 5-1**).

PROS: Consistent with ANSI principles and ERO Rules of Procedure.

Favorable to the industry as it avoids the appearance of giving FERC staff comments more weight than other participants.

Ideally should not affect the likelihood of achieving consensus on the proposed standards.

Acceptable to FERC staff.

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CONS: May cause some inefficiency as FERC staff opinion frequently seen later in the language in the Commission rulings. To not address at the standard drafting team level may result in needing to respond to a more formalized directive in a future ruling.

Option 2: Respond to FERC staff comments as quasi-directives and develop a response plan to address them.

PROS: Favorable to FERC staff.

Higher likelihood of approval (or at least less follow-up work) when the proposed standards are filed.

CONS: Not favorable to the industry due to the appearance of undocumented "backroom discussions" to which the drafting team is responding.

Higher level of importance given to FERC comments than other participants.

May violate ANSI principles and ERO Rules of Procedure.

Increased difficulty in achieving ballot approval resulting from appearances noted earlier.

Option 3: Require FERC staff to submit written comments for team consideration during an industry comment period to which the team is obliged to respond (not necessarily implement, but consider and respond).

PROS: Consistent with ANSI principles and ERO Rules of Procedure.

Provides a written record with sufficient clarity to the issues to which the drafting team can officially respond.

Ideally should not affect the likelihood of achieving consensus on the proposed standards.

CONS: Not acceptable to FERC.

Exhibit 5.a

NERC Policy Position Regarding FERC Staff Participation in Standards Drafting Team Activities

- The standard drafting team has sole responsibility for drafting and approving the language in the proposed standards that are presented to the Standards Committee for ballot.
- NERC and its Standards Committee supports the involvement of regulatory authority staff in all standards drafting team activities, where permitted by law.
- NERC recognizes that regulatory authority staff does not speak for the regulatory authority itself and, as such, the input they provide is considered advice.
- In the event regulatory authority staff does choose to participate in drafting team activities, they should be treated as any non-voting observer/participant.
- Standard drafting team members should seek out the opinion of regulatory authority staff, consider the regulatory staff input on its technical merits, and respond to written comments offered during a public posting period as it would seek opinions from, consider the technical merits of, and respond to comments offered by other industry stakeholders.
- To the extent that regulatory authority staff advice is offered to the drafting team (or members thereof) in a forum that is not public and open to all industry participants, the standard drafting team should consider the input as advice.
- If the team chooses to act on regulatory authority staff advice offered in a non public forum, the standard drafting team chairman should either (1) request the regulatory authority staff to provide the advice during an open meeting or conference call of the drafting team; or (2) document his understanding of the issues/advice presented, and include the information in an open industry comment period with the accompanying changes to the proposed standards. By doing so, the ANSI essential requirement for openness and the NERC ERO Rules of Procedure are satisfied.

Attachment C

Mandate to the Corporate Governance and Human Resources Committee Regarding the Standards Process

1. To Determine How NERC Should Handle the Violation Severity Level and Violation Risk Factor Compliance Elements

In doing so, the task force should consider the following:

Should these be subject to voting by the Registered Ballot Body as the standards currently are; should they be vetted through this process on an advisory basis only; or should NERC amend the rules to have these developed entire outside the standards voting process?

2. To Review the Opportunities to Further Prioritize the Standards Workload

In doing so, the task force should consider the following:

What should be done to better prioritize work on the most important standards? Should NERC stay the present course of improving the existing base of reliability standards or would it be preferred to begin work on a smaller set of critical standards that are performance/results based, as was the original work plan before the advent of legislation accelerated the need for standards? Can reliability and NERC's success be enhanced by focusing standard development efforts on the ten most important projects in the near term, instead of more than 30 projects in an attempt to resolve everything within three years?

3. To Reexamine the Process by Which NERC Establishes Reliability Standards Under Normal Circumstances

In doing so, the task force should consider the following:

Is the extra burden on the process that's necessary to keep ANSI certification worthwhile? How does our process compare to others that have similar aims and criticality (e.g. airlines, nuclear power, securities trading, etc.)? Would reliability be better served by foregoing NERC's ANSI accreditation and shifting to a less burdensome process that will be more responsive to reliability issues and regulatory requirements? Should there be more room for variations to the process (e.g. a full multiple re-ballot for some standards, and an abbreviated, possibly non-ANSI, process for others)? Are there "short circuits" that need to be built into the process where the BOT can interject itself or speed up the process on individual standards in certain circumstances? How can we make the Reliability Standard Development Procedure more effective to ensure due process and other ANSI requirements are met, but give the Board more flexibility when needed? Do we need both a SAR and Standard Drafting Team? Should we give the Standards Committee the explicit authority to modify the development process for a particular project and notify the Board of the action? What can NERC learn from the programs of others like the Financial Industry Regulatory Authority (FINRA)[7] and the Nuclear Regulatory Commission (NRC)[8]? Should we add a legal review of drafted standards to ensure clarity and enforceability of requirements? Should we include a formal comment period to the interpretation procedure? Should we modify the Reliability Standards Development Procedure that allows the Standards Committee to approve a SAR without a comment period or SAR drafting team when the project

[7] FINRA Compliance Tools - http://www.finra.org/RulesRegulation/ComplianceTools/index.htm.
[8] Reactor Oversight Process - http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/

scope is expressly limited to addressing regulatory directives? Is the laborious process we have in place serving the various needs that our standards program should be designed to meet — engineering rigor, consensus, tight link between standards and risks to reliability? How will NERC judge the merits of standards after looking at the violation history?

4. To Reexamine the Process by Which NERC Establishes Reliability Standards Under Urgent Action Circumstances, Especially for Cyber Security

In doing so, the task force should consider the following:

Should the NERC board review ways to improve and expedite the standards process for urgent matters including moving to a model similar to other self-regulatory organizations where a group of subject matter experts draft the standards, post the standards for comment, consider the comments, seek approval to file the standards with the appropriate government agency, and file the standards? (In such a process the stakeholders have at least two opportunities for input. One with the standard as it is being developed and again when it is filed with the regulatory agency. In such a process, there is no vote by the stakeholders.)

5. To Reexamine NERC's Relationship with FERC Regarding the Reliability Standards Approval Process

In doing so, the task force should consider the following:

How should NERC consider and respond to official FERC directives for changes to standards? Should these directives be accepted directly or addressed by the standards process? NERC can't be industry's partner and FERC's regulatory instrument simultaneously. What should the relationship between FERC and NERC look like? Define policy for FERC involvement in standard drafting team activities. Define the policy for how drafting teams should respond to FERC staff comments not associated with an order or directive. FERC staff has refrained from formally submitting these comments in accord with the ANSI process and has provided these comments verbally. The drafting team meetings need to be open and documented and FERC staff should abide by the ANSI process of not offering guidance specific to an order or directive. Does the industry-driven Reliability Standards Development Procedure conflict with the Federal Power Act 215 mandate for the ERO to develop reliability standards? Should the board have the ability to develop and approve standards apart from the Reliability Standards Development Procedure? From a policy perspective, how will NERC address situations in which the stakeholders do not approve a new or revised reliability standard in a manner that complies with a FERC directive? How can NERC encourage a beneficial engagement of regulatory staff in standard drafting team activities in a manner that encourages stakeholder involvement, innovation, and the free flow of ideas and expertise?

6. To Review Overall Stakeholder Participation in the Reliability Standards Approval Process

In doing so, the task force should consider the following:

How can NERC make the process more efficient and reflective of current trends in stakeholder participation in comment periods and balloting? Is the balance between stakeholder volunteer input and staff input appropriate? Can this model continue to attract the volunteer effort required?

Transmission Availability Data System Phase II Reporting Requirements and Timetable

Board Action Required

Approve the Phase II reporting requirements and timetable for the Transmission Availability Data System (TADS) as recommended by the NERC Planning Committee.

Recommended Phase II Reporting Requirements and Timetable

The *Transmission Availability Data System Phase II Final Report*, prepared by the Transmission Availability Data System Task Force and approved by the Planning Committee, specifies the Phase II requirements. It recommends that all Transmission Owners who are also NERC members report their Non-Automatic Outages[1] for calendar year 2010 by March 1, 2011. It also recommends that Transmission Owners maintain historical supporting information used to develop all TADS data for a five-year period so that NERC can conduct data validation reviews.

Background

On October 23, 2007, the Board of Trustees approved the collection of Automatic Outage data for certain transmission facilities ≥ 200 kV. The Phase I report, which the NERC Planning Committee approved on September 26, 2007, was the basis of the board's approval of the Phase I data collection. That report promised a subsequent Phase II effort to address the collection of Non-Automatic Outage data.

On March 13,2008, the Planning Committee approved a preliminary Phase II report that, in addition to the reporting of Non-Automatic Outage data, also addressed the collection of outage data for DC Circuits in the +/-100-199 kV range, which the Energy Information Administration (EIA) collects but which TADS currently does not. The preliminary Phase II report also addressed two issues not previously addressed in Phase I, which affect both Phase I and Phase II: (1) NERC authority to review individual Transmission Owner TADS data submittals, and (2) the future management of TADS activities.

The preliminary Phase II report, along with a *TADS Data Reporting Instruction Manual* dated April 4, 2008, were posted for comment as required by Section 1600 of NERC's *Rules of Procedure*.[2] Appendix 3 of the report describes the comments received from 64 Transmission Owners[3] plus five other entities and the task force's response to those comments. The final Phase II report includes several changes to Phase II in response to the comments received:

1. The Planning Committee agreed to delay the implementation of Phase II reporting for one year in response to numerous comments expressing concern about the Phase II schedule. Phase II TADS will now require that all Transmission Owners who are also NERC members report their Non-Automatic Outages for calendar year 2010 by March 1, 2011. (See Appendix 3, Section 3.1, pp. 7-8.)
2. The Planning Committee, in light of the objections expressed by certain Transmission Owners to the Phase II expansion, agreed to review the benefits of Phase II reporting after five years of data has been collected and to consider the Phase II reporting

[1] Non-Automatic Outages include Planned Outages and Operational Outages, as defined in the TADS Task Force Phase II Report.
[2] All materials related to the request for comments are available at http://www.nerc.com/filez/tadstf.html.
[3] The 64 Transmission Owners providing comments represented 31.4 percent of all TOs that will provide Phase I data.

requirements for re-approval by the Planning Committee and Board of Trustees at that time. (See Appendix 3, Section 3.2, pp. 8-10.)

3. The Task Force, in response to Nebraska Public Power District's request that we add a "forced outage rate" metric, agreed to specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each Transmission Owner can calculate its own "forced outage rate" metric. (See Appendix 3, Section 3.6. p. 17.)

4. The Task Force, in response to National Grid's comment that Transmission Owners should be allowed to enter data in local time instead of Universal Coordinated Time (UTC), agreed to modify webTADS in the future to allow data to be entered in local time *if* it is entered via the graphical user interface (GUI). However, it will be converted to UTC and stored in webTADS in UTC. Bulk-loaded data entry must still be in UTC. This will be clarified in a future update of the Manual. (See Appendix 3, Section 3.9, p. 22.)

Attachment 1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transmission Availability Data System Phase II Final Report

Prepared by the Transmission Availability Data System Task Force for the NERC Planning Committee

Approved by the Planning Committee on: September 11, 2008

to ensure the reliability of the bulk power system

September 11, 2008

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Table of Contents

1. Executive Summary

1.1. Background

On October 23, 2007, the NERC Board of Trustees approved the mandatory implementation of Phase I Transmission Availability Data System (TADS) which required U.S. Transmission Owners[1] (TOs) on the NERC Compliance Registry to report Automatic Outages beginning in 2008 in a NERC-prescribed format for the following Elements:[2]

- AC Circuits ≥ 200 kV (Overhead and Underground Circuits). Radial circuits are included.
- Transformers with ≥ 200 kV low-side voltage
- AC/DC Back-to-Back Converters with ≥ 200 kV AC voltage, both sides
- DC Circuits with ≥ +/-200 kV DC voltage

Phase I was developed by the Transmission Availability Data System Task Force (TADSTF, or TF) of NERC's Planning Committee. The details of Phase I are described in the *Transmission Availability Data System Revised Final Report* dated September 26, 2007, which may be downloaded at http://www.nerc.com/filez/tadstf.html. That report included a commitment by the TF to develop Phase II:

> "Phase II will add a requirement that TOs report scheduled outage and manual unscheduled outage data beginning in calendar year 2009. Phase II was added as a result of discussions with officials of the U.S. Energy Information Administration (EIA) on May 16, 2007, and we are recommending it in order to have TADS serve as a single source to NERC and EIA for transmission outage data. We will propose that outage reporting framework to the Planning Committee at its March 2008 meeting."[3]

1.2. Changes from the Preliminary Phase II Report

A *Transmission Availability Data System Preliminary Phase II Report* dated March 13, 2008 ("preliminary Phase II report") was approved by the Planning Committee. In addition to considering additional outage reporting, the preliminary Phase II report also addressed the collection of outage data for DC Circuits in the +/-100-199 kV range, which EIA collects but which TADS does not. Finally, the preliminary Phase II report addressed two issues that were not previously addressed in Phase I which affect both Phase I and Phase II: (i) NERC authority to review individual Transmission Owner TADS data submittals, and (ii) the future management of TADS activities.

The preliminary Phase II report, along with a *TADS Data Reporting Instruction Manual* dated April 4, 2008 ("Manual"), were posted for comment as required by Section 1600 of NERC's *Rules of Procedure*.[4] Appendix 3 describes the comments received and our

[1] Non-U.S. Transmission Owners were asked for Phase I TADS data, but their response is voluntary.
[2] Definitions in Appendix 2 are capitalized in this report.
[3] See p. 1 of the September 26, 2007 report.
[4] All materials related to the request for comments are available at http://www.nerc.com/filez/tadstf.html.

responses to those comments. We received comments from 64 Transmission Owners plus five other entities.[5] In this final Phase II report, we included several changes to Phase II that responded to the comments received:

1. In response to numerous comments expressing concern about the Phase II schedule, we delayed implementation by one-year. Phase II TADS will now require that all Transmission Owners who are also NERC members report their Non-Automatic Outages for calendar year 2010 by March 1, 2011 (i.e., Non-Automatic Outages from January 1, 2010 through December 31, 2010). See Appendix 3, Section 3.1, pp. 7-8.
2. In response to concerns as to whether Phase II TADS data is a benefit to NERC, we recommended that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion. We also recommended that the benefits of Phase II be demonstrated after five years of data has been collected. This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan**.** Furthermore, we recommended that this demonstration be followed by re-approval of Phase II data collection by the Planning Committee and the Board of Trustees. See Appendix 3, Section 3.2, pp. 8-10.
3. In response to Nebraska Public Power District's request that we add a "forced outage rate" metric, we declined to add their suggested formula as a general metric because it may be defined differently by different TOs. However, we will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric. See Appendix 3, Section 3.6. p. 17.
4. In response to National Grid's comment that TOs should be allowed to enter data in local time instead of Universal Coordinated Time (UTC) since webTADS has this capability, we will modify webTADS in the future to allow data to be entered in local time *if* it is entered via the graphical user interface (GUI). However, it will be converted to UTC and stored in webTADS in UTC. Bulk-loaded data entry must still be in UTC. We will clarify this in a future update of the Manual. See Appendix 3, Section 3.9, p. 22.

1.3. Phase II Design

Phase II defines a framework for the collection of Non-Automatic Outages which complements the Phase I Automatic Outage structure. Phase II thus completes the specification of a NERC-wide approach to quantify or measure system performance and reliability. Phase II has two categories of Non-Automatic Outages, along with several Cause Codes for each category:

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[5] The 64 Transmission Owners providing comments represented 31.4% of all TOs that will provide Phase I data.

- Planned Outage: A Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred. Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation of an outage of another TADS Element are not reportable.[6]

  Planned Outage Cause Codes:
  - Maintenance and Construction
  - Third-Party Request
  - Other Planned Outage

- Operational Outage: A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property), or to maintain the system within operational limits, and that cannot be deferred.

  Operational Outage Cause Codes:
  - Emergency
  - System Voltage Limit Mitigation
  - System Operating Limit Mitigation, excluding System Voltage Limit Mitigation
  - Other Operational Outage

With regard to collecting outage data for DC Circuits in the +/-100-199 kV range which is now included EIA Form 411, Schedule 7, there is only one DC Circuit in North America that falls in this category. Reporting outages in this single voltage class would display the metrics of a single TO. Our policy is not to display metrics if the TO's name and confidential information could be identified. Therefore, we will not include this additional voltage class in Phase II.

While the collection of Non-Automatic Outage data by Transmission Owners is a mixed practice, the TF noted several uses as well as limitations associated with Non-Automatic Outage data. The list below begins with the Non-Automatic Outage data uses.

1. Non-Automatic Outage data will complement Phase I Automatic Outage data, resulting in our ability to capture almost all transmission Element outages. Since almost all Element outages will be recorded, the calculation of certain Phase I metrics – the Mean Time Between Sustained Outages, or mean "Up Time" (also referred to as Mean Time Between Failure) and Availability Percentage – will now be more accurate.
2. Complete transmission outage information may influence NERC Reliability Standards development.
3. Complete transmission outage information could allow for improved system analysis by bridging gaps between the operating environment and planning assumptions.
4. For U.S. Transmission Owners who are subject to EIA reporting requirements, the reporting of Non-Automatic Outages to NERC could avoid a duplicative reporting

[6] The exclusion of "setup switching" or "restoration switching" outages recognizes that they are not part of an intended Planned Outage and should not be reported.

requirement to EIA. The data from Phase I and Phase II TADS can be summarized by NERC to provide EIA the same data it now requires in EIA Form 411, Schedule 7, except for data on DC Circuits in the +/- 100-199 kV range.

5. No Reliability Standard or NERC rule (in NERC's *Rules of Procedure*) requires the systematic recording of historic system topology for the purpose of analyzing events. TADS will begin to fill this need by collecting both Automatic and Non-Automatic Outage data.

These are some limitations in the use of Non-Automatic Outage data.

1. Trending of Non-Automatic Outage metrics *within* a Regional Entity may be useful, but comparisons *between* Regional Entities are inappropriate for the same reasons provided in the Phase I report.
2. Trending Planned Outages is not an indication of the total amount of maintenance or construction being performed on the TADS Elements. For example, live–line circuit maintenance and substation equipment maintenance that does not require an Element outage is not captured. Therefore, correlations between Phase I Automatic Outages and Phase II Non-Automatic Planned Outages should be approached with caution.

With respect to EIA Form 411, Schedule 7, the reporting of this data to EIA was made voluntary for 2008 (for 2007 data), with the status of Schedule 7 beyond 2008 to be resolved in future discussions among NERC, EIA, federal users of Schedule 7 data, and Office of Management and Budget (OMB) with the possible substitution of information derived from TADS for Schedule 7 data. OMB was to be the final arbiter. NERC held one meeting with EIA and other federal users on February 7, 2008.

EIA's follow-up March 11, 2008 comments on TADS were as follows: NERC was asked to provide information on how TADS data reporting would be validated to ensure quality information and how TADS data reporting would be enforced; FERC staff attendees expressed the desire for TADS to be expanded to transmission voltages of 100 kV and higher; and further discussions would be required regarding TADS data confidentiality.

Following those March 11 comments, NERC and EIA agreed to the following: EIA will accept summary Schedule 7 data, thereby eliminating the need to address their previous confidentiality concerns; Schedule 7 should remain voluntary through 2010, with NERC providing EIA with the voluntary data it receives from the regions; mandating Schedule 7 will be re-addressed in the Electricity 2011 project, which will take up the re-authorization of EIA data collection forms, including Form 411.

1.4. Who Must Report Phase II Data

Based upon some of the comments received, we felt that we should clarify which TOs are required to report Phase II TADS data. The submission of Phase II TADS data will be mandatory for all U.S. Transmission Owners who are on the NERC Compliance Registry. Non-U.S. Transmission Owners on the NERC Compliance Registry who are also NERC members are required to comply with NERC's *Rules of Procedure*, and because Phase II TADS data was requested in accordance with Section 1600, these non-U.S. Transmission Owners too must provide Phase II TADS data.[7]

1.5. Phase II Data and Metrics

We used the same format for Non-Automatic Outage data collection as we did for Automatic Outage data. In addition to a description of the Element that had an outage, Non-Automatic Outages only require the reporting of an Outage Start Time, an Outage Duration, an outage category (Planned or Operational), and a Cause Code.[8] While less data per outage is required for a Non-Automatic Outage as compared to an Automatic Outage, the number of Non-Automatic Outages is expected to be significantly greater than the number of Automatic Outages.

The following Phase II metrics will be calculated:

1. Non-Automatic Outage frequency per Element (Planned, Operational, and total).
2. For Planned and Operational Outages:
    i. Outage Duration per Element.
    ii. Mean Element outage time
    iii. Median Element outage time
3. Percent of Elements with zero Non-Automatic Outages.
4. The maximum percentage of simultaneous Element Outages. Since TADS will have almost all outage data including outage start time and duration, we will be able to calculate the maximum percentage of simultaneous outages that occurred for an Element on a Transmission Owner or Regional Entity basis.

Some TOs may want to develop metrics that combine Automatic Outage data with Non-Automatic Outage data. For example, the EIA's term for "unscheduled outages" combines Automatic Outage Data with Operational Outages having an Emergency Outage Cause Code. Some TOs might consider this data to be the basis of a "forced outage rate" calculation, while others may consider different parameters in the term "forced outage rate." We will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric.

1.6. Additional Phase II Recommendations

In the Phase I report, we noted that the Regional Entities will be spot checking TO-submitted TADS data for potential errors. We propose conducting data validation

[7] Phase I was approved by the NERC Board of Trustees prior to the addition of Section 1600 to the *Rules of Procedure.* Because NERC's Phase I TADS approval relied upon Section 39.2(d) of the Federal Energy Regulatory Commission's regulations, 18 C.F.R. § 39.2(d), Phase I is mandatory on all U.S. Transmission Owners. However, most non-U.S. Transmission Owners have indicated that they will voluntarily comply with Phase I.

[8] Non-Automatic Outages do not require an Event ID Code, an AC Multi-Owner Common Structure Flag, a Fault Type, two Cause Codes (Initiating and Sustained), and an Outage Mode Code.

reviews of TADS data submissions with the submitting Transmission Owners. These reviews would cover the Transmission Owner's most recent TADS data submittal and evaluate the TO's process for collecting and validating its TADS data. This review has the single objective of improving the quality of TADS data. Eventually all TOs would be reviewed. The results of a review will only be shared with the TO that was reviewed. Reviews will not be made public.

- To the extent that a review indicates systematic data entry errors, data entries for previous years may need to be revised. We will limit the period for historic corrections to five (5) years. Therefore, TOs would need to maintain historical supporting information used to develop its TADS data for a five-year period. We will not require TOs to maintain any supporting information for outages that are not reported such as certain Planned Outages that are covered under the 30-minute exclusion criterion.

In response to concerns as to whether Phase II TADS data is a benefit, we recommend that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion. We also recommend that the benefits of Phase II be demonstrated after five years of data has been collected. This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan. Furthermore, we recommend that this demonstration be followed by re-approval of Phase II data collection by the Planning Committee and the Board of Trustees.

Finally, we recommend that the TADSTF be converted into a working group under the Planning Committee after Phase II has been implemented with the overall mission of oversight of TADS.

1.7. Phase II Schedule

The table below shows the steps leading to approval of Phase II by NERC's Board of Trustees.

Phase II TADS Approval Schedule

September 10-11, 2008	Planning Committee meeting to review and approve the final Phase II TADS report.
October 29, 2008	Board of Trustees decides on whether to give Phase II TADS its approval for mandatory 2010 reporting.

The table (next page) shows the TADS reporting schedule for Phase II submission of 2010 data, including the development schedule for webTADS. For 2010 data, Phase II will be on the same reporting schedule as Phase I, with all data being submitted through the Regional Entities (REs). Unlike Phase I, Phase II will not have a special first quarter data submission. However, as the table shows, a Phase II dry-run period in 2009 is designed to allow TOs that will be bulk loading Phase II TADS data to verify the compatibility of their in-house data extraction and transfer protocols with webTADS data input requirements using actual or dummy 2009 data. TOs that will not be bulk loading webTADS data may also test their ability to input actual or dummy 2009 data. Dry-run testing is completely optional, but we believe that TOs who avail themselves of this option will be better prepared for 2010 implementation.

Phase II TADS Timetable for 2010 Reporting Year

Late Nov. 2008	NERC completes Phase II webTADS requirements and submits to OATI.
Feb. 1, 2009	NERC will publish final specifications for data input and error checking so that TOs may use the specifications to modify their data collection systems.
Feb 1-July 1, 2009	OATI will complete changes to webTADS for Phase II, including system testing with dummy data.
July 1-Dec. 1, 2009	NERC and OATI will conduct Phase II webTADS training. We recognize that some TOs will have different personnel entering Non-Automatic Outage data into webTADS, and therefore we have allowed a long training period.
July 1-Dec. 31, 2009	“Dry run” data entry permitted into webTADS by TOs for any part of their actual or dummy 2009 data. Any 2009 Phase II data which a TO enters will not be retained in webTADS after December 31, 2009.
Jan. 1, 2010	TOs may submit Phase II data in webTADS
Mar. 1, 2011	TOs complete data entry of Phase II data into webTADS

2. Phase II Design

2.1. Non-Automatic Outages

A Non-Automatic Outage is defined as an outage which results from the manual operation (including supervisory control) of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

- For comparison, an Automatic Outage is defined as an outage which results from the automatic operation of switching device, causing an Element to change from an In-Service State to a not In-Service State. A successful AC single-pole (phase) reclosing event is not an Automatic Outage.

We wanted the Non-Automatic Outage framework to have the same “look and feel” as the Automatic Outage framework we adopted in Phase I so that Transmission Owners could easily add it to their ongoing Phase I collection. The final TADS structure for Phase II accomplishes this goal. We also wanted Phase II to be compatible with EIA transmission outage needs. While we examined the same outage collection frameworks described in our Phase I report, in the end we chose a Phase II structure very similar to the structure recommended by the Electric Power Research Institute reference listed in the Phase I report.[9]

For TADS, Non-Automatic Outages are subdivided into two categories: Planned Outages and Operational Outages, which are defined below.

- Planned Outage: A Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred. Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation or restoration of an outage of another TADS Element are not reportable.[10]
- Operational Outage: A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property), or to maintain the system within operational limits, and that cannot be deferred.

2.1.1. Planned Outage Cause Codes

We adopted three Planned Outage Cause Codes:

1. Maintenance and Construction: Use for Planned Outages associated with maintenance and construction of electric facilities, including testing. This includes requests from any entity that is defined in the NERC Functional Model.[11]

[9] See Section 2.2 of the *Transmission Availability Data System Revised Final Report* dated September 26, 2007.
[10] The exclusion of “setup switching” or “restoration switching outages recognizes that they are not part of an intended Planned Outage and should not be reported.
[11] The Functional Model is available at http://www.nerc.com/files/Functional_Model_Technical_Document_V3_for_OC_and_PC_approval_06De

2. Third-Party Request: Use for Planned Outages that are taken at the request of a third party such as highway departments, the Coast Guard, etc.

3. Other Planned Outage: Use for Planned Outages for reasons not included in the above list, including human error.

With respect to the Maintenance and Construction Cause Code, we considered separate codes for maintenance and construction. However, since in practice, the outage of a facility for maintenance is often scheduled to coincide with construction, we felt that asking TOs to distinguish between them would not be reasonable.

2.1.2. Operational Outage Cause Codes

We adopted four Operational Outage Cause Codes:

1. Emergency: Use for Operational Outages that are taken for the purpose of avoiding risk to human life, damage to equipment, damage to property, or similar threatening consequences.

2. System Voltage Limit Mitigation: Use for Operational Outages taken to maintain the voltage on the transmission system within desired levels (i.e., voltage control).[12]

3. System Operating Limit Mitigation, excluding System Voltage Limit Mitigation: Use for Operational Outages taken to keep the transmission system within System Operating Limits, except for System Voltage Limit Mitigation. The term "System Operating Limit" is defined in the NERC *Glossary of Terms Used in Reliability Standards* and is excerpted below.

   > "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 Ratings (Applicable pre- and post-Contingency Stability Limits)
   > - Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
   > - System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). "

   Do not include actions in the last category (System Voltage Limits) because this is included in the previous "System Voltage Limit Mitigation" Cause Code.

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c06.pdf. As an example, an outage is requested by a Generation Operator for purposes of completing an interconnection of its facilities would be classified in the Maintenance and Construction category. A Load-Serving Entity which requests an outage to make repairs to its substation would also be reported in this category.

[12] A separate Cause Code for System Voltage Limit Mitigation was required because we believe this will be a dominant Operational Outage cause.

4. Other Operational Outage: Use for Operational Outages for reasons not included in the above list, including human error.

2.2. Data for DC Circuits in the +/-100-199 kV Range

While TADS has a minimum voltage level of 200 kV for outage reporting, EIA collects DC Circuit data at the +/- 100-199 kV level.[13] There is only one DC Circuit in North America that falls in this category. Reporting outages in this single voltage class would display the metrics of a single TO. Our policy is not to display metrics if the TO's name and confidential information could be identified. Therefore, we will not include this additional voltage class in TADS Phase II.

2.3. Who Must Report Phase II Data

Based upon some of the comments received, we felt that we should clarify which TOs are required to report Phase II TADS data. The submission of Phase II TADS data will be mandatory for all U.S. Transmission Owners who are on the NERC Compliance Registry. Non-U.S. Transmission Owners on the NERC Compliance Registry who are also NERC members are required to comply with NERC's *Rules of Procedure*, and because Phase II TADS data was requested in accordance with Section 1600, these non-U.S. Transmission Owners too must provide Phase II TADS data.[14]

2.4. Intended Uses and Limitations of Non-Automatic Outage Data and Metrics

The collection of historic Non-Automatic Outage data by Transmission Owners is a mixed practice.

- EPRI recommends planned outage metrics for use in internal applications such as corporate strategic planning and reliability management but not for external applications such as benchmarking or regulatory assessment.
- Some regions, such as the former East Central Area Reliability (ECAR), Mid-America Interconnected Network (MAIN), and Mid-Continent Area Power Pool (MAPP) regions collected all transmission outages for over 20 years. However, no recommendations were made by them as a result of the collection and reporting of the planned outage data over that same period. They did make formal observations in their summary reports as to outage duration and cause.
- Five of the eight NERC regions submitted EIA Schedule 7 data in 2006 and 2007, which included unscheduled and scheduled outage data.
- Others have not collected such data for statistical purposes under the assumption that most Non-Automatic Outages are Planned Outages which are taken when reliability is not jeopardized. The Canadian Electricity Association (CEA)

[13] For AC Circuits, EIA and TADS both start at 200 kV.
[14] Phase I was approved by the NERC Board of Trustees prior to the addition of Section 1600 to the *Rules of Procedure*. Because NERC's Phase I TADS approval relied upon Section 39.2(d) of the Federal Energy Regulatory Commission's regulations, 18 C.F.R. § 39.2(d), Phase I is mandatory on all U.S. Transmission Owners. However, most non-U.S. Transmission Owners have indicated that they will voluntarily comply with Phase I.

collects equipment forced outage data that are consistent with the classification of TADS Automatic Outages plus Operational Outages. CEA has felt that the value of Planned Outage data is not commensurate with the effort involved in collecting it.

In the new NERC "electricity reliability organization" era, we believe NERC should collect almost all transmission outage data for several reasons. The list below begins with the Non-Automatic Outage data uses.

1. Non-Automatic Outage data will complement Phase I Automatic Outage data, resulting in our ability to capture almost all transmission Element outages. Since almost all Element outages will be recorded, the calculation of certain Phase I metrics (discussed in Section 4) will now be more accurate.
2. Complete transmission outage information may influence NERC Reliability Standards development.
3. Complete transmission outage information could allow for improved system analysis by bridging gaps between the operating environment and planning assumptions. For example, Transmission Planners could compare historical Planned Outages for a period with previously forecasted outages for the same period allowing them to assess whether their outage representation for planning is valid.[15] TOs, Transmission Planners, and Planning Coordinators could compare historic Planned Outages to historic load levels to determine the frequency of such outages during peak load periods.

   From a planning perspective, if planned outages are not properly accounted for in the planning of the system, insufficient facilities may be built, making day-to-day reliability worse. Several TPL standards (TPL-002-0, TPL-003-0, and TPL-004-0) have a requirement that planned outages be explicitly considered. In TPL-002-0, this is found in R1.3.12:

   > "Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

   Historical Planned Outage data could help Transmission Planners with this requirement.
4. For U.S. Transmission Owners who are subject to EIA reporting requirements, the reporting of Non-Automatic Outages to NERC could avoid a duplicative reporting requirement to EIA. The next section describes the present status of EIA Form 411, Schedule 7.
5. No Reliability Standard or NERC rule (in NERC's *Rules of Procedure*) requires the systematic recording of historic system topology for the purpose of analyzing events. TADS will begin to fill this need by collecting both Automatic and Non-Automatic Outage data. Since we only require the submission of TADS data

[15] To be clear, Phase II will *not* be collecting forecasted Planned Outage data; it will be collecting historic Planned Outage data.

annually, we recognize that the submission of TADS data into webTADS may not occur until months after an event. The requirement to collect TADS outage data means that TOs could, by special request from NERC, provide outage data if required to help NERC analyze an event, and the fact that such data will be entered into a structured TADS database will be helpful.

These are some limitations in the use of Non-Automatic Outage data.

1. Trending of Non-Automatic Outage metrics *within* a Regional Entity may be useful, but comparisons *between* Regional Entities are inappropriate for the same reasons provided in the Phase I report.
2. Trending Planned Outages is not an indication of the total amount of maintenance or construction being performed on the TADS Elements. Therefore, correlations between Phase I Automatic Outages and Phase II Non-Automatic Planned Outages should be approached with caution.
    - Maintenance and construction are bundled in our reporting for practicality as discussed previously, so maintenance is not captured separately.
    - A TADS Element maintenance and construction outage could be due to maintenance and construction on a non-TADS Element.
    - Planned Outage data does not capture the total amount of maintenance performed. For example, live–line circuit maintenance and substation equipment maintenance that does not require an Element outage is not captured.

2.5. Status of EIA Form 411, Schedule 7

EIA has indicated that it must receive the same type of data on EIA Form 411, Schedule 7, from TADS if TADS is to be an acceptable substitute for Schedule 7. In 2007, EIA asked that Form 411 be made mandatory, a requirement that would only affect U.S. Transmission Owners. NERC filed comments (see Appendix 1) with the Office of Management and Budget (OMB), asking that Schedule 7 either be made voluntary or eliminated altogether. As an alternative, NERC recommended using its TADS database to make available to EIA the same type of data on EIA Form 411. Following discussions between NERC, EIA, and OMB in late December 2007, Schedule 7 was made voluntary for 2008 (for 2007 data), with the status of Schedule 7 beyond 2008 to be resolved in future discussions among NERC, EIA, federal users of Schedule 7 data, and OMB about the possible substitution of information derived from TADS for Schedule 7 data. OMB was to be the final arbiter.

On February 7, 2008, an initial meeting was held among representatives from OMB, the Department of Energy (including EIA), the Department of Justice, the Federal Energy Regulatory Commission (FERC), and NERC staff to determine whether (a) TADS would meet the needs of federal users of transmission outage data, and (b) what barriers exist to making information derived from TADS available to federal users.

- On the first issue, EIA will solicit input from the federal user community on the adequacy of Phase I. With respect to Phase II, federal users will provide comments during the Phase II public comment period.

- On the second issue, from NERC's perspective, the main barrier to providing TADS data to federal users is ensuring that mechanisms are in place to protect confidential TADS data, including critical energy infrastructure information (CEII) and sensitive proprietary information from public access or public disclosure. Section 1500 of NERC's *Rules of Procedure* defines confidential information and sets forth the procedures for release of confidential information in NERC's possession.
    - A procedure for FERC (and other applicable electric reliability organization (ERO) governmental authorities) to request confidential information from NERC is set forth in Section 1505 of NERC's *Rules of Procedure*.[16]
    - NERC and EIA discussed the possibility of EIA requesting summarized non-confidential aggregated data and metrics from NERC and identifying NERC as the source of the data. In such a case, EIA would not have possession of confidential TADS data; instead, it would receive aggregated information produced by NERC. Information provided to EIA that might identify a single Transmission Owner's confidential information could either be removed or combined with data from another Voltage Class to prevent such disclosure. NERC and EIA agreed to continue discussions regarding these issues.
    - The Department of Justice representative did not make any comments.

Federal users were asked to provide comments to EIA by March 7, 2008 on (a) the adequacy of Phase I and (b) how to address NERC's concerns regarding confidentiality.

EIA's follow-up March 11, 2008 comments on TADS were as follows: NERC was asked to provide information on how TADS data reporting would be validated to ensure quality information and how TADS data reporting would be enforced; FERC staff attendees expressed the desire for TADS to be expanded to transmission voltages of 100 kV and higher; and further discussions would be required regarding TADS data confidentiality.

Following those March 11 comments, NERC and EIA agreed to the following: EIA will accept summary Schedule 7 data, thereby eliminating the need to address their previous confidentiality concerns; Schedule 7 should remain voluntary through 2010, with NERC providing EIA with the voluntary data it receives from the regions; mandating Schedule 7 will be re-addressed in the Electricity 2011 project, which will take up the re-authorization of EIA data collection forms, including Form 411.

TADS Phase I and Phase II can be used to derive the Schedule 7 requirements as shown in Figure 1 on the next page.[17] NERC can also meet the EIA time schedule for providing this data for 2011 reporting of 2010 data.

[16] Each ERO governmental authority would be able to access confidential information for Transmission Owners that it regulates, e.g., FERC would only be able to access TADS data for U.S. Transmission Owners, and an appropriate Canadian provincial regulatory body would only be able to access TADS data for its provincial Transmission Owners.

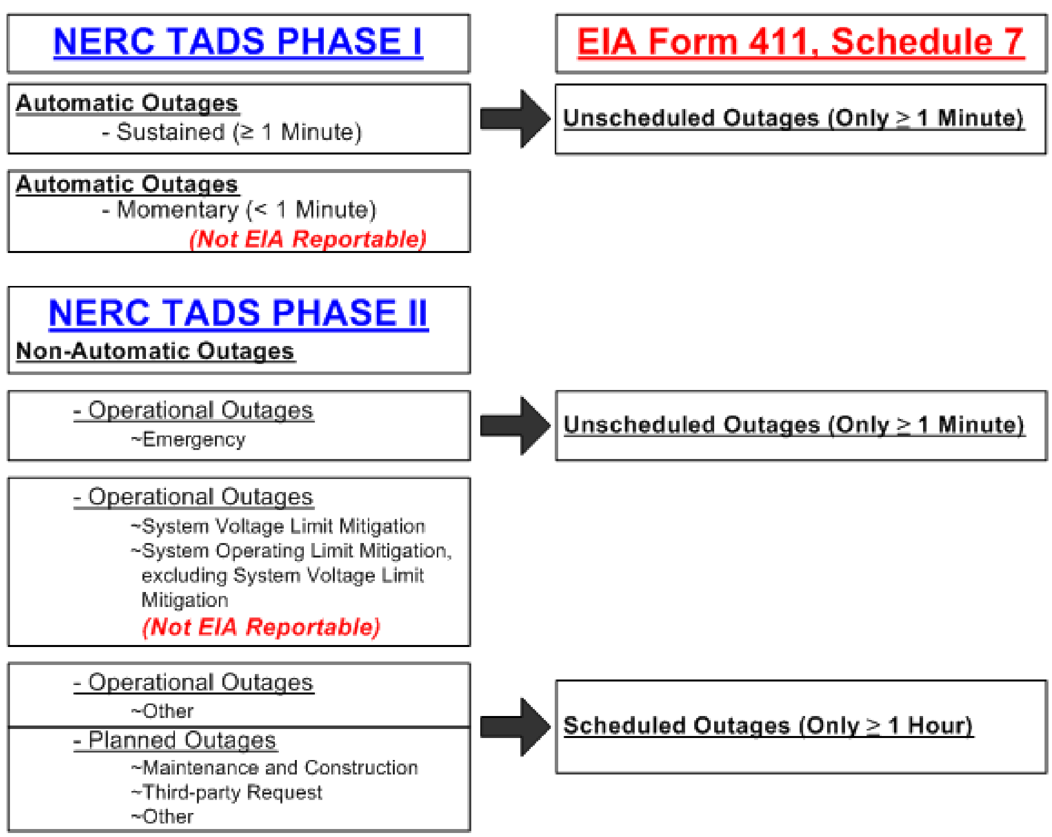
[17] As discussed in Section 2.2, we do not propose to collect TADS data for the one DC Circuit in the +/- 100-199 kV level which is now required in Schedule 7.

- Phase I TADS Sustained Outages and Phase II TADS Operational Outages classified as “Emergency” become Schedule 7 unscheduled outages. The Emergency-classified Operational Outage would be sorted by NERC to exclude outages that are less than one minute.
- Phase II TADS Planned Outages (all classifications) and Operational Outages classified as “Other” become EIA scheduled outages. By NERC sorting on the outage durations, we would exclude outages of less that one hour duration for EIA. Note that Phase II Planned Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation or restoration of an outage of another TADS Element will not be reported in TADS.

Certain TADS outage data will not be reportable to EIA:

- Phase I Momentary Outages
- Phase II Operational Outages classified as “System Voltage Limit Mitigation” and “System Operating Limits, excluding System Voltage Limit Mitigation.”

Figure 1: NERC TADS Compared to EIA Form 411, Schedule 7



3. Phase II Data Reporting

Like Phase I, which reports each individual Automatic Outage, Phase II will require the reporting of each reportable Non-Automatic Outage. Outages will be reported for each Element type: AC Circuits, DC Circuits, Transformers, and AC/DC Back-to-Back Converters. However, the Phase II outage reporting will be simpler compared to Phase I.

Each Element outage will require the following data:

1. An Outage ID Code. This is a unique outage code assigned by the TO.
2. Data that defines the physical location of the Element. For example, for AC Circuits, the Substation Names that define the circuit are required, while for Transformers, the Substation Name where the Transformer is located is required. In addition, a TO Element Identifier, an alphanumeric name of the Element (such as a circuit number) is required to be provided by the Transmission Owner.
3. The Element's Voltage Class.
4. For AC or DC Circuits, whether it is an Overhead or Underground Circuit.
5. Whether the Non-Automatic Outage is a Planned Outage or an Operational Outage.
6. The Outage Cause Code. Three codes are provided for Planned Outages and four codes are provided for Operational Outages.
7. The Outage Start Time. The date (mm/dd/yyyy) and time (hh:mm), rounded to the minute, that the Automatic Outage of an Element started. Outage Start Time is expressed in Coordinated Universal Time (UTC), not local time.
8. The Outage Duration, rounded to the nearest minute.
9. An Outage Continuation Flag which indicates whether the outage continues into the next reporting year or started in the prior year.

Figure 2 shows the Non-Automatic Outage data required for an AC Circuit compared to the same form for an Automatic Outage. The column structure has been kept the same, with unutilized Automatic Outage columns labeled "NA." While less data per outage is required for a Non-Automatic Outage compared to an Automatic Outage, the number of Non-Automatic Outages is expected to be significantly greater than the number of Automatic Outages.

Figure 2

AC Circuit Automatic Outage Data

AC Circuit Momentary and Sustained Outage Data

			Circuit Substation Boundaries										Cause Codes			
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
Outage ID Code	Event ID Code [2]	Voltage Class	AC Substation Name #1	AC Substation Name #2	AC Substation Name #3	TO Element Identifier (AC Circuit)	OH or UG?	AC Multi-Owner Com. Struct. Flag [3]	Fault Type	Outage Initiation Code	Start Time (mm/dd/yyyy hh:mm) (UTC) [4]	Outage Duration hhhh:mm [5]	Initiating Cause Code [6]	Sustained Cause Code [7]	Outage Mode	Outage Continuation Code [8]
100	A-2008	200-299 kV	Brown	Smith		BwSh#1	OH	0	No fault	AC Substation-Initiated	5/5/2008 13:04	1:20	Lightning	Failed Protection System Equipment	Dependent Mode Initiating	0

AC Circuit Non-Automatic Outage Data

AC Circuit Planned and Operational Outage Data

			Circuit Substation Boundaries													
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
Outage ID Code	NA	Voltage Class	AC Substation Name #1	AC Substation Name #2	AC Substation Name #3	TO Element Identifier (AC Circuit)	OH or UG?	NA	NA	Non-Automatic Outage Type	Start Time (mm/dd/yyyy hh:mm) (UTC) [3]	Outage Duration hhhh:mm [4]	Planned Outage Cause Code [5]	Operational Cause Code [6]	NA	Outage Continuation Code [7]
200	NA	200-299 kV	Brown	Smith		BwSh#1	OH	NA	NA	Planned	10/5/2008 15:08	21:20	Maintenance & Construction	NA	NA	0

4. Phase II Metrics

The *Transmission Availability Data System Revised Final Report* dated September 26, 2007 describes a set of Phase I metrics in Section 4 of the report and in a table in Appendix 4. Phase II metrics will build on the Phase I metrics, and because almost all Element outages are being recorded, the calculation of the Mean Time Between Sustained Outages, or mean "Up Time" (also referred to as Mean Time Between Failure) and Availability Percentage will now be more accurate.[18]

As we stated in Section 4 of the Phase I report dated September 26, 2007:

> "We have not established a comprehensive set of uniform metric calculations since we expect that it will take some work with the data itself to tell us which combinations provide meaningful information."

This same principle applies to the Phase II TADS metrics recommended below - they are a starting point.

The common metrics listed below will be reported to describe the performance of each Element for the reporting year. When possible, the standard deviation of metrics will be calculated and statistical confidence intervals reported. Similar metrics can be developed for each subcategory or combination of cause codes.

1. Non-Automatic Outage frequency per Element (Planned, Operational, and total).
2. For Planned and Operational Outages:
    i. Outage Duration per Element
    ii. Mean Element outage time
    iii. Median Element outage time
3. Percent of Elements with zero Non-Automatic Outages.[19]
4. The maximum percentage of simultaneous Element Outages. Since TADS will have almost all outage data including outage start time and duration, we will be able to calculate the maximum percentage of simultaneous outages that occurred for an Element on a Transmission Owner or Regional Entity basis. This could be refined and sub-divided by voltage class. For example, if a TO has 25 AC Circuits in the 200-299 kV, this metric would display the maximum percentage that were out simultaneously. The associated simultaneous outage time could also be displayed. With complete historic outage data, we could map the historic unavailability of a set of Elements or of all Elements. TOs and regions could compare outages to historic load

[18] Although outages that qualify for the 30-minute exclusion of Planned Outages will not be recorded, these are expected to be minimal in total duration.

[19] Each TO will provide the number of Elements without an outage, with NERC calculating the percentage. While TADS requires the number of Elements to be reported, the TO-provided information is required because TADS does not require an Element list that provides each Element with a unique descriptor.

levels. Transmission Planners will be able to evaluate assumptions used in modeling the power system for planning purposes.

The basic set of Phase II TADS metrics are shown on the Table 1 (next two pages), along with the two updated metrics from Phase I.

- For Mean Time to Repair in Phase I, we are calculating a standard deviation and a confidence interval for Phase I data, and will do so for the Mean Element Planned Outage Time and Mean Element Operational Outage Time in Phase II data. We also believe that the median times add perspective to the mean times since one can easily tell if a few events affected the mean by comparing the two.

Some TOs may want to develop metrics that combine Automatic Outage data with Non-Automatic Outage data. For example, the EIA's term for "unscheduled outages" in Figure 1 combines Automatic Outage Data with Operational Outages having an Emergency Outage Cause Code. Some TOs might consider this data to be the basis of a "forced outage rate" calculation, while others may consider different parameters in the term "forced outage rate." We will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric.

Finally, Phase II metrics should not be the sole driver of actual maintenance practices. Maintenance practices should be based upon reliability considerations and good utility practice.

Table 1: TADS Phase II Metrics and Updated Phase I Metrics

No.	Metric	Formula	Units	Acronymn
	Element Outage Frequency			
1	Element Total Non-Automatic Outage Frequency	Total Non-Automatic Outages / Total Elements	No. Non-Automatic Outages per Element per year	TNAOF
2	Element Planned Outage Frequency	Total Planned Outages / Total Elements	No. Planned Outages per Element per year	POF
3	Element Operational Outage Frequency	Total Operational Outages / Total Elements	No. Operational Outages per Element per year	OOF
	Element Outage Duration and Outage Time			
4	Element Total Non-Automatic Outage Duration Time	Total Non-Automatic Outage Hours / Total Elements	Average no. of Non-Automatic Outage hours per Element per year	TNAODT
5	Mean Total Non-Automatic Outage Time	Total Non-Automatic Outage Hours / Total Non-Automatic Element Outages	Average no. of Non-Automatic Outage Hours per outaged Element per year	TNAMPOT
6	Median Total Non-Automatic Outage Time	The time when 50% of the Mean Total Non-Automatic Outage Time minutes are greater than	Median no. of Non-Automatic Outage Hours per outaged Element	TNAMdPOT
7	Element Planned Outage Duration Time	Total Planned Outage Hours / Total Elements	Average no. of Planned Outages hours per Element per year	PODT
8	Mean Element Planned Outage Time	Total Planned Outage Hours / Total Planned Element Outages	Average no. of Planned Outage Hours per outaged Element per year	MPOT
9	Median Element Planned Outage Time	The time when 50% of the Mean Planned Outage Time minutes are greater than this figure	Median no. of Planned Outage Hours per outaged Element	MdPOT
10	Element Operational Outage Duration Time	Total Operational Outage Hours / Total Elements	Average no. of Operational Outages hours per Element per year	OODT
11	Mean Element Operational Outage Time	Total Operational Outage Hours / Total Operational Element Outages	Average no. of Operational Outage Hours per outaged Element per year	MOOT
12	Median Element Opertional Outage Time	The time when 50% of the Mean Operational Outage Time minutes are greater than this figure	Median no. of Operational Outage Hours per outaged Element	MdOOT

Table 1: TADS Phase II Metrics and Updated Phase I Metrics (cont'd)

	Element Availability			
12	Percentage of Elements with Zero Non-Automatic Outages	Total Elements with Zero Non-Automatic Outages / Total Elements	Percentage	PCNAZO
13	Maximum Percent of Simultaneous Element Outages	This will be calculated by taking all Element outages and searching for the time when the maximum no. are out due to Sustained Automatic Outages and Non-Automatic Outages.	Percentage	MSIM
	Phase I Revised Metrics with Phase II Outage Data			
Phase I	Mean Time Between Sustained Element Outages (Mean "Up Time"). Also referred to as Mean Time Between Failures.	(Total Element Hours - Total Sustained Outage Hours) / Total Sustained Element Outages	Mean (average) no. of hours of operation of an Element before it fails	MTBF[1]
Updated w. Phase II	Mean Time Between Sustained Element Outages (Mean "Up Time"). Also referred to as Mean Time Between Failures.	(Total Element Hours - Total Sustained Outage Hours - Total Non-Automatic Outage Hours) / Total Sustained Element Outages	Mean (average) no. of hours of operation of an Element before it fails	MTBF
Phase I	Element Availability Percentage	1- (Total Sustained Outage Hours / Total Element Hours) * 100	Percentage	APC[1]
Updated w. Phase II	Element Availability Percentage	1- [(Total Sustained Outage Hours + Total Non-Automatic Outage Hours) / Total Element Hours] * 100	Percentage	APC

[1]These Phase I metrics are from Appendix 4 of the *Transmission Availability Data System Revised Final Report* dated September 26, 2007.

5. Additional Phase II Recommendations

5.1. NERC Review of TADS Submittals by TOs

In the Phase I report, we noted that the Regional Entities will be spot checking TO-submitted TADS data for potential errors. We will be conducting workshops to discuss data collection and interpretation practices with the goal of ensuring both accuracy and consistency of TADS data submitted by TOs.

We are now proposing to conduct data validation reviews of TADS data submissions for Automatic and Non-Automatic Outages with the submitting Transmission Owners. These reviews would cover the Transmission Owner's most recent TADS data submittal and evaluate the TO's process for collecting and validating its TADS data. This review has the single objective of improving the quality of TADS data. Eventually all TOs would be reviewed. The results of these reviews will only be shared with the TO that was reviewed. Reviews will not be made public.

To the extent that a review indicates systematic data entry errors, data entries for previous years may need to be revised. We will limit the period for historic corrections to five (5) years. Therefore, TOs would need to maintain historical supporting information used to develop its TADS data for a five-year period.[20] For example, suppose a TO submits 2008 TADS data by March 1, 2009. The TO would need to maintain the supporting information it used to develop its 2008 TADS data until March 1, 2013. This would allow data to be corrected for the five previous years: 2008–2012.

5.2. Phase II Demonstration of Benefits

Many commenters expressed concern as to whether the collection of Phase II TADS data is a benefit to NERC. **We recommend that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion**. **We also recommend that the benefits to NERC of Phase II be demonstrated after five years of data has been collected. This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan. Furthermore, we recommend that this demonstration be followed by re-approval of Phase II by the Planning Committee and the Board of Trustees for Phase II data collection to be continued.** The five-year data collection period will conclude with 2014 data, which will be collected in 2015. The demonstration of Phase II benefits should be performed on or before August 15, 2015 to allow sufficient time for Planning Committee and Board of Trustees action.

5.3. Future Role of the TADSTF

A "task force" under NERC's parlance is a subgroup that is formed to address a specific issue. When that issue has been addressed, a task force is typically dissolved. However,

[20] We will not require TOs to maintain any supporting information for outages that are not reported such as Planned Outages that are covered under the 30-minute exclusion criterion.

we believe that the TADSTF should be converted to a working group under the Planning Committee with a scope that is defined as follows:

- Support TADS implementation
- Support NERC staff training of TOs
- Support NERC staff coordination with TOs and REs
- Develop a process for soliciting and evaluating TADS improvements and recommend selected improvements to the Planning Committee for approval. Ultimate approval will come after posting the proposed changes, receiving comments, revising the proposed improvements, obtaining Planning Committee re-approval, and finally obtaining NERC Board of Trustees approval.
- Develop the format for NERC public reports as well as confidential TO reports. Provide input to NERC staff on draft public reports and recommend TADS public reports to the Planning Committee for approval.

6. Phase II Schedule

The schedule for the approval of Phase II by the Board of Trustees is in Table 2

Table 2: Phase II TADS Approval Schedule

September 10-11, 2008	Planning Committee meeting to review and approve the final Phase II TADS report.
October 29, 2008	Board of Trustees decides on whether to give Phase II TADS its approval for mandatory 2010 reporting.

This schedule provides for Phase II outage reporting beginning with Non-Automatic Outage data in 2010.

Table 3 shows the TADS reporting schedule for Phase II submission of 2010 data, including the development schedule for webTADS. For 2010 data, Phase II will be on the same reporting schedule as Phase I, with all data being submitted through the Regional Entities (REs). Unlike Phase I, Phase II will not have a special first quarter data submission. However, as Table 3 shows, a Phase II dry-run period in 2009 is designed to allow TOs that will be bulk loading Phase II TADS data to verify the compatibility of their in-house data extraction and transfer protocols with webTADS data input requirements using actual or dummy 2009 data. TOs that will not be bulk loading webTADS data may also test their ability to input actual or dummy 2009 data. Dry-run testing is completely optional, but we believe that TOs who avail themselves of this option will be better prepared for 2010 implementation.

Table 3: Phase II TADS Timetable for 2010 Reporting Year

Late Nov. 2008	NERC completes Phase II webTADS requirements and submits to OATI.
Feb. 1, 2009	NERC will publish final specifications for data input and error checking so that TOs may use the specifications to modify their data collection systems.
Feb 1-July 1, 2009	OATI will complete changes to webTADS for Phase II, including system testing with dummy data.
July 1-Dec. 1, 2009	NERC and OATI will conduct Phase II webTADS training. We recognize that some TOs will have different personnel entering Non-Automatic Outage data into webTADS, and we therefore have allowed a long training period.
July 1-Dec. 31, 2009	“Dry run” data entry permitted into webTADS by TOs for any part of their actual or dummy 2009 data. Any 2009 Phase II data which a TO enters will not be retained in webTADS after December 31, 2009.
Jan. 1, 2010	TOs may submit Phase II data in webTADS
Mar. 1, 2011	TOs complete data entry of Phase II data into webTADS

Appendix 1. NERC Correspondence to OMB re: Schedule 7

NERC's letter to the Office of Management and Budget follows.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

David R. Nevius
Senior Vice President
Director of Reliability Assessment &
Performance Analysis

October 24, 2007

OMB Desk Officer for DOE *sent via e-mail to* ***Nathan_J._Frey@omb.eop.gov***
Office of Information and Regulatory Affairs
726 Jackson Place, NW
Washington, DC 20503

Dear Sir or Madam:

NERC Comments on Form EIA-411

In response to the Energy Information Administration's (EIA's) Federal Register notice on September 28, 2007, page no. 55193, the North American Electric Reliability Corporation (NERC) submits these comments to the Office of Management and Budget (OMB) regarding Form EIA-411, "Coordinated Bulk Power Supply Program Report," as proposed by EIA for a three-year extension.

NERC was certified as the Electric Reliability Organization by the Federal Energy Regulatory Commission (FERC or Commission) on July 20, 2006. NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by FERC and governmental authorities in Canada. Within the U.S., NERC has specific statutory authority to request information from owners, users, and operators of the bulk power system. FERC's regulations, at 18 C.F.R. Section 39.2(d) (2007), states:

> "Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity."

With the exception of Schedule 7 as proposed in EIA-411, NERC does not oppose the EIA's proposed *new* mandatory reporting requirements.

However, NERC strenuously objects to EIA's proposal to make Schedule 7 a mandatory requirement going forward. Schedule 7 asks for the same historic transmission outage data that was voluntarily requested in current Form EIA-411 Schedule 7. The provision of such information should either be eliminated or remain voluntary as it has been in the past for the following reasons:

1. The transmission outage data requested on Schedule 7 is inadequate, and, therefore, of no value to the industry.[1] For this reason, NERC undertook the development of its own transmission outage data collection effort. **On October 23, 2007, NERC's Board of Trustees authorized the mandatory collection of transmission outage data from all North American transmission owners (approximately 300), starting with automatic outage data in 2008.** This new data collection initiative, referred to as Phase I Transmission Availability Data System (TADS), took a year to develop, during which time NERC kept EIA staff closely informed. For automatic outages, Phase I TADS will collect more detailed, and, therefore, more useful data for NERC, its members, and government users such as EIA who may access TADS data under NERC's policies. The scope of TADS is described in the *Transmission Availability Data System Revised Final Report* dated September 26, 2007. A second document, *TADS Data Reporting Instruction Manual* dated October 17, 2007, contains instructions for reporting TADS data to NERC. The manual contains instructions for twelve TADS data input forms, and several forms are due in December 2007. The report, manual, and data input forms may be downloaded at http://www.nerc.com/~filez/tadstf.html.

2. Making Schedule 7 mandatory will require U.S. transmission owners to report 2007 calendar year data. This will impose a burden on many owners since they were not notified of the mandatory collection requirement *before* 2007. As a result, they will have to manually construct the requested data from historic outage records. Because the Schedule 7 data itself is inadequate for industry use, OMB approval of mandatory Schedule 7 data collection is tantamount to approving a "make work" data collection effort. That effort will also divert resources needed to implement Phase I TADS.

3. As described in the Section 2.3 of the September 26, 2007 report, NERC has kept EIA apprised of its efforts to develop TADS. NERC is implementing TADS in two phases:

   a. Phase I will require transmission owners to report automatic outage data beginning in calendar year 2008.

   b. Phase II will add planned outage and manual unscheduled outage data in calendar year 2009. Phase II design is underway, and its implementation will be subject to normal NERC approvals.

4. NERC has the expertise and the authority to collect the transmission outage data needed by the U.S. electric industry and is willing to make such information available to the Federal government. The TADS data collection effort will exceed, in both quality and quantity, the information requested in Schedule 7 of the Form EIA-411. Once the TADS data base is populated with the data NERC is requiring to be reported, the data reported under Schedule 7 will be totally unnecessary.

[1] In its *Supporting Statement for Electric Power Surveys, OMB Number 1905-0129*, EIA states (on p. 6) that the data in Schedule 7 is used by EIA "to monitor reliability planning, track changes in outage rates, and determine issues affecting transmission outages." Despite this claim, the limited Schedule 7 data cannot meet the uses described by EIA. As an example, EIA data cannot determine "outage rates" because the number of transmission facilities is not requested on Schedule 7.

Therefore, NERC requests that OMB direct EIA either to eliminate Schedule 7 from Form EIA-411 *or* make Schedule 7 voluntary. By either action, OMB will avoid a duplicative, unnecessary, and burdensome data collection effort.

Respectively submitted,

David R. Nevius

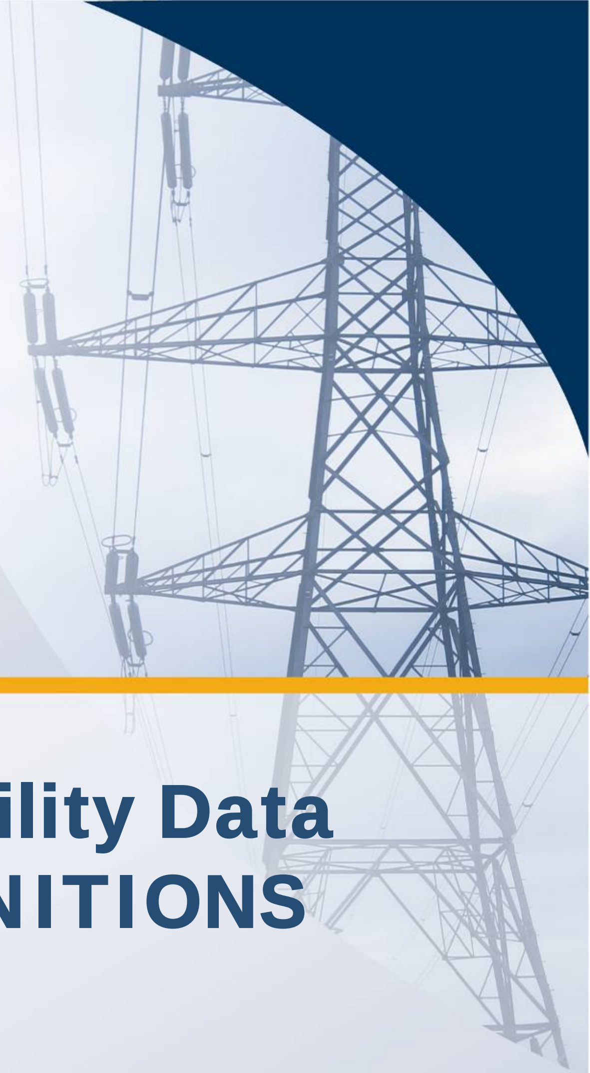
cc: Ms. Grace Sutherland, EIA's Statistics and Methods Group, by e-mail to grace.sutherland@eia.doe.gov

Appendix 2. TADS Definitions

The Phase II definitions added in Appendix 2 are highlighted in yellow. Only one change was made to Appendix 2 from the April 4 version of the definitions in the preliminary Phase II report: an example was added to Planned Outage Cause Codes (Section G) based upon comments received**.**

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Transmission Availability Data System (TADS) DEFINITIONS

September 11, 2008

to ensure the reliability of the bulk power system

116-390 Village Blvd., Princeton, NJ 08540
609.452.8060 | 609.452.9550 fax
www.nerc.com

Table of Contents

A. TADS Population Definitions

1. Element

The following are Elements for which TADS data are to be collected:

1. AC Circuits ≥ 200 kV (Overhead and Underground)
2. Transformers with ≥ 200 kV low-side voltage
3. AC/DC Back-to-Back Converters with ≥ 200 kV AC voltage, both sides
4. DC Circuits with ≥ +/-200 kV DC voltage

An Element may also be referred to as a "TADS Element" in the Manual. They have the same meaning.

2. Protection System

Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.[1]

3. AC Circuit

A set of AC overhead or underground three-phase conductors that are bound by AC Substations. Radial circuits are AC Circuits.

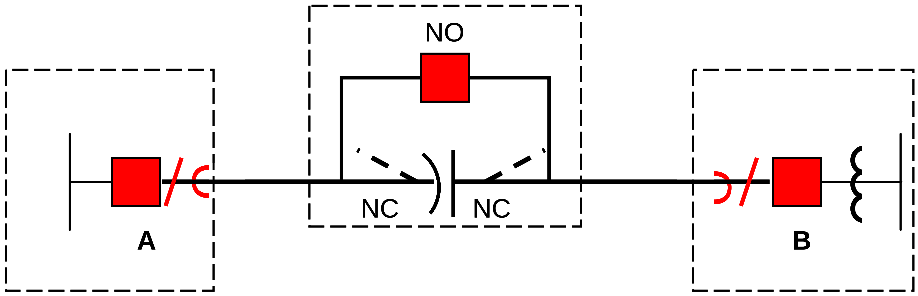
The boundary of an AC Circuit extends to the transmission side of an AC Substation. A circuit breaker, Transformer, and their associated disconnect switches are not considered part of the AC Circuit but instead are defined as part of the AC Substation. The AC Circuit includes the conductor, transmission structure, joints and dead-ends, insulators, ground wire, and other hardware, including in-line switches. The AC Circuit includes in-line switches used to sectionalize portions of the AC Circuit as well as series compensation (capacitors and reactors) that is within the boundaries of the AC Circuit even if these 'in-line' devices are within an AC Substation. If these devices are not within the AC Circuit boundaries, they are not part of the AC Circuit but instead are part of the AC Substation. The diagrams on the next several pages explain this concept. The red arcs define the AC Circuit boundaries.[2]

In Figure 1 (next page), the series capacitor, bypass circuit breaker, and numerous disconnect switches are in a fenced AC Substation that is within the boundaries of the AC Circuit itself. When the series capacitor is connected and the bypass breaker is open, the capacitor and its disconnect switches are part of the AC Circuit. When the bypass breaker is closed, the bypass breaker and its disconnect switches (not shown) are part of the AC Circuit.

[1] This definition is in the current NERC *Glossary of Terms Used in Reliability Standards*.
[2] To simplify future diagrams, disconnect switches may not be shown.

Figure 1

Two in-line NC switches and one series capacitor are part of the AC Circuit between AC Substations A and B. When the bypass breaker and its disconnect switches (not shown) are closed and the capacitor switches opened, the breaker and its switches are part of the AC Circuit.



In Figure 2, the series reactor and in-line switches are part of the AC Circuit since they are within the AC Circuit boundaries even though they are within the AC Substation boundaries. In Figure 3, they are not part of the AC Circuit because they are not within the AC Circuit boundaries.

Figure 2

Two in-line NC switch and one series reactor are part of the AC Circuit between AC Substations A and B. The AC Circuit boundaries are the breaker disconnect switch in AC Substation A and the high-side disconnect switch on the Transformer in AC Substation B.

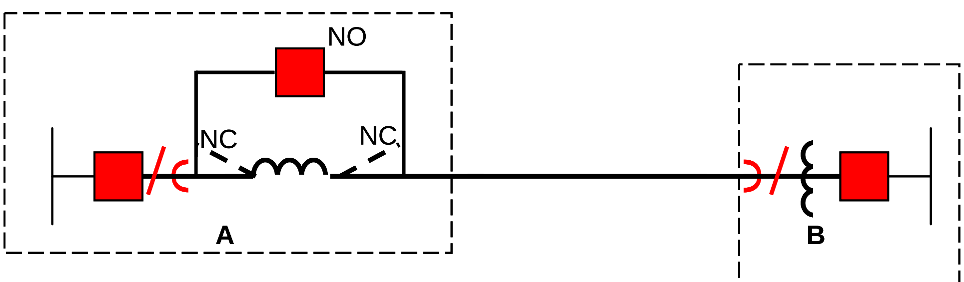
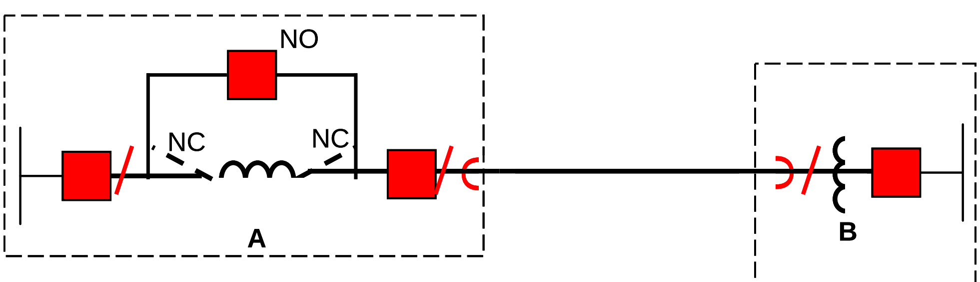


Figure 3

Two in-line NC switches and one series reactor are part of the AC Substation and not part of the AC Circuit between AC Substations A and B



4. Transformer

A bank comprised of three single-phase transformers or a single three-phase transformer. A Transformer is bounded by its associated switching or interrupting devices.

5. AC Substation

An AC Substation includes the circuit breakers and disconnect switches which define the boundaries of an AC Circuit, as well as other facilities such as surge arrestors, buses, Transformers, wave traps, motorized devices, grounding switches, and shunt capacitors and reactors. Series compensation (capacitors and reactors) is part of the AC Substation if it is not part of the AC Circuit. See the explanation in the definition of "AC Circuit." Protection System equipment is excluded.

6. AC/DC Terminal

A terminal that includes all AC and DC equipment needed for DC operation such as PLC (power-line carrier) filters, AC filters, reactors and capacitors, Transformers, DC valves, smoothing reactors and DC filters. On the AC side, an AC/DC Terminal is normally bound by AC breakers at the AC Substation bus where it is connected. On the DC side, it is bound by DC converters and filters. Protection System equipment is excluded.

7. AC/DC Back-to-Back Converter

Two AC/DC Terminals in the same location with a DC bus between them. The boundaries are the AC breakers on each side.

8. DC Circuit

One pole of an Overhead or Underground DC line which is bound by an AC/DC Terminal on each end.

9. Overhead Circuit

An AC or DC Circuit that is not an Underground Circuit. A cable conductor AC or DC Circuit inside a conduit which is *not* below the surface is an Overhead Circuit. A circuit that is part Overhead and part Underground is to be classified based upon the majority characteristic (Overhead Circuit or Underground Circuit) using Circuit Miles.

10. Underground Circuit

An AC or DC Circuit that is below the surface, either below ground or below water. A circuit that is part Overhead Circuit and part Underground Circuit is to be classified based upon the majority characteristic (Overhead Circuit or Underground Circuit) using Circuit Miles.

11. Circuit Mile

One mile of either a set of AC three-phase conductors in an Overhead or Underground AC Circuit, or one pole of a DC Circuit. A one mile-long, AC Circuit tower line that carries two three-phase circuits (i.e., a double-circuit tower line) would equate to two Circuit Miles. A one mile-long, DC tower line that carries two DC poles would equate to two Circuit Miles. Also, a one mile-long, common-trenched, double-AC Circuit Underground duct bank that carries two three-phase circuits would equate to two Circuit Miles.

12. Multi-Circuit Structure Mile

A one-mile linear distance of sequential structures carrying multiple Overhead AC or DC Circuits. (Note: this definition is *not* the same as the industry term "structure mile." A Transmission Owner's Multi-Circuit Structure Miles will generally be less than its structure miles since not all structures contain multiple circuits.)

If a line section contains two or more Multi-Circuit Structures which form one or more multi-circuit spans, the total span length can be measured and the associated mileage should be reported in the 'Multi-Circuit Structure Mile' total inventory. If multiple circuits are connected to only one common structure, that structure should be ignored for outage and inventory mileage purposes.

13. Voltage Class

The following voltages classes will be used for reporting purposes:

1. 200 – 299 kV
2. 300 – 399 kV
3. 400 – 499 kV
4. 500 – 599 kV
5. 600 – 799 kV

For Transformers, the Voltage Class reported will be the high-side voltage, even though the cut-off voltage used in the definition is referenced on the low-side. Voltages are operating voltages.

B. Outage Reporting Definitions

1. Automatic Outage

An outage which results from the automatic operation of switching device, causing an Element to change from an In-Service State to a not In-Service State. A successful AC single-pole (phase) reclosing event is not an Automatic Outage.

2. Momentary Outage

An Automatic Outage with an Outage Duration less than one (1) minute. If the circuit recloses and trips again within less than a minute of the initial outage, it is only considered one outage. The circuit would need to remain in service for longer than one minute between the breaker operations to be considered as two outages.

3. Sustained Outage[3]

An Automatic Outage with an Outage Duration of a minute or greater.

[3] The TADS definition of Sustained Outage is different that the NERC *Glossary of Term Used in Reliability Standards* definition of Sustained Outage which is presently only used in FAC-003-1. The glossary defines a Sustained Outage as follows: "The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure." The definition is inadequate for TADS reporting for two reasons. First, it has no time limit that would distinguish a Sustained Outage from a Momentary Outage. Second, for a circuit with no automatic reclosing, the outage would not be "counted" if the TO has a successful manual reclosing under the glossary definition.

4. Non-Automatic Outage

An outage which results from the manual operation (including supervisory control) of a switching device, causing an Element to change from an In-Service State to a not In-Service State.

5. Planned Outage

A Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred. Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation or restoration of an outage of another TADS Element are not reportable.

6. Operational Outage

A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property), or to maintain the system within operational limits, and that cannot be deferred.

7. AC Multi-Owner Common Structure Flag

This flag identifies whether the outaged AC Circuit is on common structures with another circuit that is owned by a different Transmission Owner. This flag does not apply to DC Circuits which by default are all assumed to be on common structures with the circuits owned by the same Transmission Owner.

Flag	Flag Interpretation
0	Not applicable. The circuit is not on common structures with another circuit, or the circuit is on common structures, but all circuits are reported by the same Transmission Owner. No analysis of the Event ID Code or the Event Type Number is required by the Regional Entity.
1	Circuit is on common structures with another circuit that is being reported by a different Transmission Owner. The Regional Entity will need to examine Outage Start Times with this same flag to determine whether a second circuit had an outage with nearly the same Outage Start Time, and if so, whether the TOs properly coordinated their Event ID Codes and Event Type Numbers.

8. In-Service State

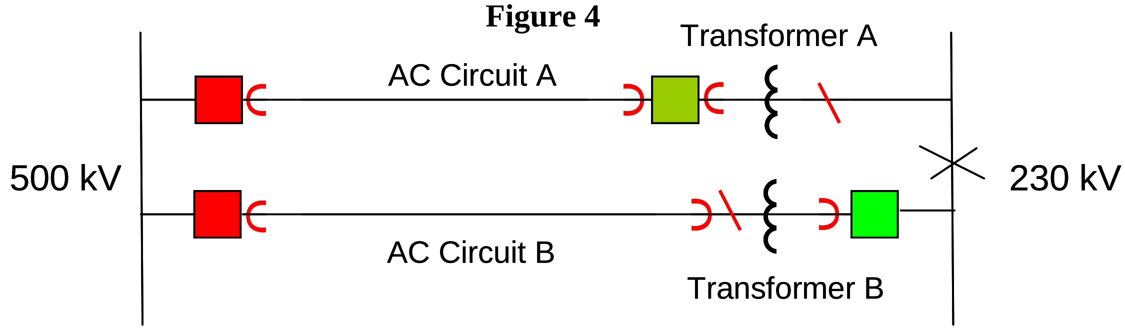
An Element that is energized and fully connected to the system. Examples of reportable AC Circuit and Transformer Automatic Outages are illustrated below. Non-Automatic Outage examples are in Appendix 10.

In Figure 4, AC Circuit A is bound by the disconnect switches (not shown)[4] of two breakers, and Transformer A is bound by a breaker and a disconnect switch. AC Circuit B is bound by a breaker and a disconnect switch, and Transformer B is bound by a breaker and a disconnect switch. 230 kV bus fault opens the green breakers. The TADS Transformers each report an outage. AC Circuit A reports an outage, but AC Circuit B

[4] For simplification, disconnect switches may not be show in some figures. When a circuit breaker or Transformer disconnect switch define an AC Circuit boundary, we may just refer to the circuit breaker and the Transformer as defining the boundary without reference to their disconnect switches.

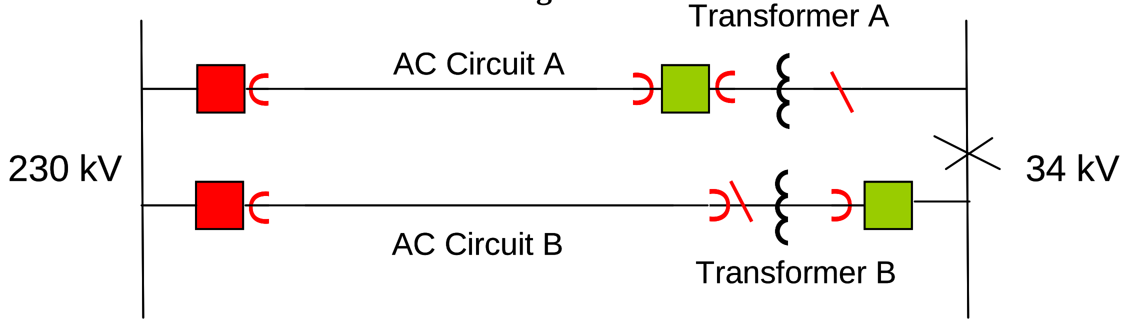
does not. It is defined by the breaker on the left and the disconnect switch on the right. Since the breaker associated with AC Circuit B did not experience and automatic operation, it was not outaged. It remains fully connected by the breaker and the disconnect switch.

Figure 4



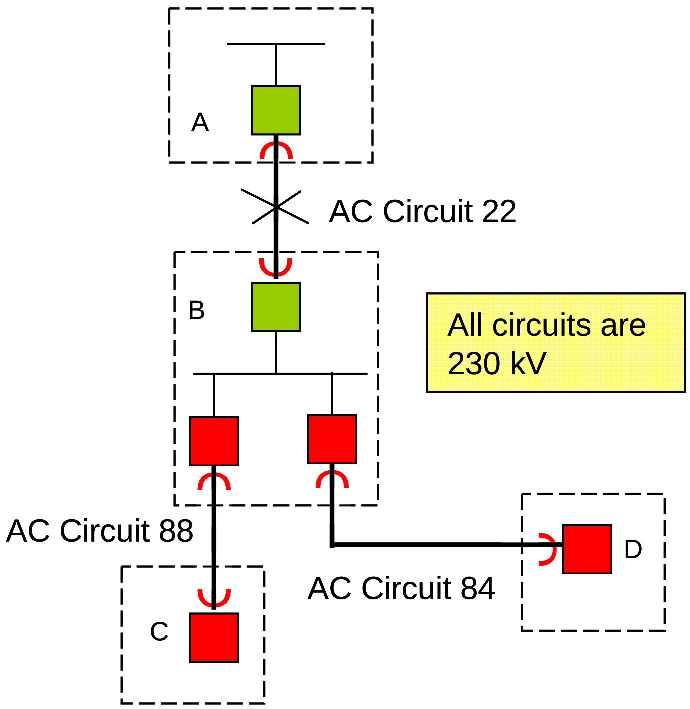
In Figure 5, we have a similar situation, except that the Transformers are not reportable since their low-side voltages are less that 200 kV. The AC Circuit outages are reportable exactly the same as in Figure 4; however, the Transformer outages are not reportable.

Figure 5



In Figure 6 (next page), AC Circuit 22, the only source connecting AC Substations A and B, has a fault. As a result, AC Circuits 84 and 88 are deenergized but remain fully connected. Three outages are reported: circuits 22, 84, and 88. None of them meet the In-Service State requirement of being energized *and* fully connected.

Figure 6



An exception that an Element be "fully connected" to be considered in an In-Service State is provided for a multi-terminal AC Circuit with a Transformer on one terminal that shares a breaker with the circuit.

Figure 7

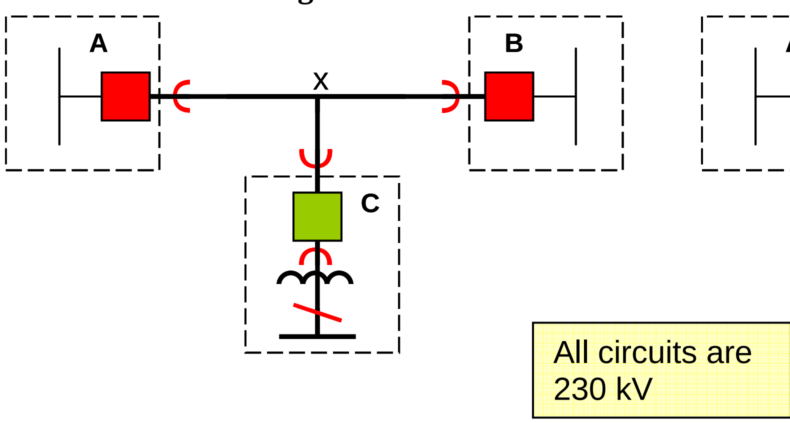
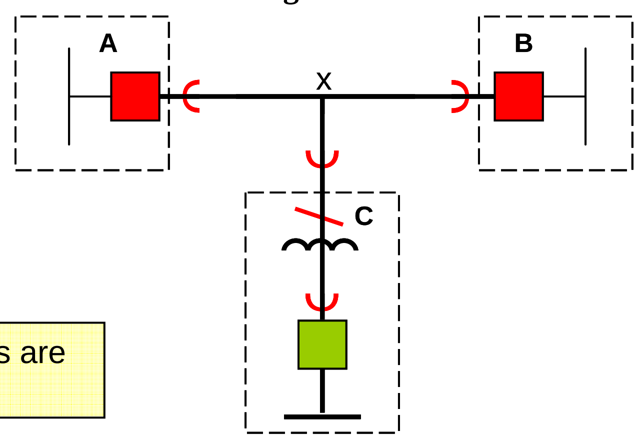


Figure 8



In both figures, the AC Circuit is bounded by AC Substations "A," "B," and "C" as indicated by the red arcs. Each Transformer's boundaries are the red disconnect switch and the red arc before the breaker. Note that the Transformer in either figure may *or* may not be a reportable Element (i.e., one with a low-side voltage ≥ 200 kV).

Assume that each Transformer is out of service as a result of the operation of its associated breaker (indicated in green). In Figure 7, the AC Circuit would normally be considered out of service since the breaker at AC Substation C, which is shared by the AC Circuit and the Transformer, is open. Nevertheless, if all other portions of the AC Circuit are in service, the entire AC Circuit is considered to be in an In-Service State even if the Transformer is out of service. Because TADS does not recognize partial outage states, the multi-terminal exception above was developed so as to not overstate the outage contribution of a multi-terminal configuration of this type. In Figure 8, the open breaker is not shared by the AC Circuit, and the AC Circuit remains fully connected. Thus, the exception does not apply in this case since the AC Circuit is fully connected even though the Transformer out of service.

9. Substation, Terminal, or Converter Name

For Automatic Outages or Non-Automatic Outages of AC Circuits and DC Circuits, the termination name at each end of the circuit will be reported to help identify *where* the circuit is located. For AC Circuits, these are the AC Substation Names; for DC Circuits, these are the AC/DC Terminal Names. For AC/DC Back-to-Back Converters, this is the Converter Station Name.

10. TO Element Identifier

An alphanumeric name that the TO must enter to identify the Element which is outaged (e.g., a circuit name.)

11. Outage Start Time

The date (mm/dd/yyyy) and time (hhhh:mm), rounded to the minute, that the Automatic Outage or Non-Automatic Outage of an Element started. Outage Start Time is expressed in Coordinated Universal Time (UTC), not local time. TADS data is reported on a calendar-year basis, and the TADS Data Reporting Instruction Manual addresses the recording of the Outage Start time of a Sustained Outage that starts in one reporting year and concludes in another reporting year.

12. Outage Duration

The amount of time from the Outage Start Time to when the Element is fully restored to its original or to normal configuration, including equipment replacement. Outage Duration is expressed as hours and minutes, rounded to the nearest minute. Momentary Outages are assigned a time of zero Outage Duration. TADS data is reported on a calendar-year basis, and the TADS Data Reporting Instruction Manual addresses the recording of the Outage Durations of an outage that starts in one reporting year and concludes in another reporting year.

13. Outage Continuation Flag

Not all outages start and end in the same reporting year. This flag describes that characteristic for an outage.

Flag	Flag Interpretation
0	Outage began and ended within the reporting year
1	Outage began in the reporting year but continues into the next reporting year.
2	Outage started in another (previous) reporting year.

14. Outage Identification (ID) Code

A unique alphanumeric identifier assigned by the Transmission Owner to identify the reported outage of an Element.

15. Event

An Event is a transmission incident that results in the Automatic Outage (Sustained or Momentary) of one or more Elements.

16. Event Identification (ID) Code

A unique alphanumeric identifier assigned by the Transmission Owner to an Event. Because outages that begin in one reporting year and end in the next reporting year must have the same Event ID Code, the code must have the reporting year appended to it to ensure its uniqueness. For example, an Event ID Code may be W324-2008. This unique Event ID Code establishes an easy way to identify which Automatic Outages are related to one another as defined by their Outage Mode Codes (see Section D).

1. An Event associated with a Single Mode Outage will have just one Event ID Code.
2. Each outage in a related set of two or more outages (e.g., Dependent Mode, Dependent Mode Initiating, Common Mode, or Common Mode Initiating) shall be given the same Event ID Code.

17. Event Type Number

A code that describes the type of Automatic Outage. The following Event Type Numbers will be used initially:

Event Type No.	Table 1 Category from the TPL Standards	Description
10	B	Automatic Outage of an AC Circuit or Transformer with Normal Clearing.
20	B	Automatic Outage of a DC Circuit with Normal Clearing.
30	C	Automatic Outage of two ADJACENT AC Circuits on common structures with Normal Clearing.
40	C	Automatic Outage of two ADJACENT DC Circuits on common structures with Normal Clearing.
50	NA	Other - please describe the event (optional)

To qualify for an Event Type No. 30 or 40, the outages must be a direct result of the circuits occupying common structures. These characteristics will generally apply.

1. The Outage Initiation Codes are either Element-Initiated or Other-Element Initiated.
2. The Outage Mode Codes are one of the following: (a) Dependent Mode Initiating (one outage) and Dependent Mode (second outage); (b) Common Mode Initiating and Common Mode (two outages); or (c) both Common Mode (two outages).

Event Type No. 30 and 50 Examples

These are examples of Events that are Event Type No. 30:

1. A tornado outages two circuits on common structures. In this example, the outage is Element-Initiated and Common Mode. This is an Event Type No. 30 because the loss of both circuits was directly related to them being on the same structures.

2. On one circuit, a conductor breaks (outaging the circuit), and the conductor swings into a second circuit on common structures. The first circuit outage is Element-Initiated and Dependent Mode Initiating; the second circuit outage is Other-Element Initiated and Dependent Mode. This is an Event Type No. 30 because the second circuit's outage was a result of it being on common structures as the first circuit.

These Events are not an Event Type No. 30; instead, they are an Event Type No. 50.

1. Two AC Circuits on common structures are outaged due to a bus fault in the AC Substation where the circuits terminate. Both outages are Substation-Initiated and Common Mode. Because the outages are not a result of the two circuits being on common structures, it is not an Event Type No. 30. Therefore, it is an Event Type No. 50.
2. Two AC Circuits are on common structures and terminate at the same bus. Lightning strikes one AC Circuit, but the breaker fails to open due to a failure of a relay to operate properly. The second circuit, which is connected to the same bus, is outaged as a result of the failure of first circuit's breaker to open. The first outage is an Element-Initiated and Dependent Mode Initiating; the second outage is Other Facility-Initiated and Dependent Mode. (Note: the relay is excluded as part of an AC Substation, making the Outage Initiation Code "Other-Facility Initiated" and not "Substation-Initiated.") Because the outages are not a result of the two circuits being on common structures, it is not an Event Type No. 30. Therefore, it is an Event Type No. 50.

18. Fault Type

The descriptor of the fault, if any, associated with each Automatic Outage of an Element. Several choices are possible for each Element outage:

1. No fault
2. Phase-to-phase fault (P-P)
3. Single phase-to-ground fault (P-G)
4. Phase-to-phase-to ground (P-P-G), 3P, or 3P-G fault
5. Unknown fault type

The Fault Type for each Element outage may be determined from recorded relay targets or by other analysis. TOs should use the best available data to determine (1) whether a fault occurred on each outaged Element and, if so, (2) what type of fault occurred. Relay targets should be documented as soon as practical after a fault and the targets re-set to prepare for the next fault. If a single fault results in several Element outages, the protective relay targets associated with each Element indicate the Fault Type for that Outage. Relay targets are not a fool proof method to determine the Fault Type; however, they may be the best available data to determine Fault Type. An Element whose relays did not indicate a fault should be reported as "No fault."

Example: A 500 kV AC Circuit has a single phase-to-ground fault that also results in an Outage of a 500/230 kV Transformer. The AC Circuit outage would have "Single phase-to-ground fault (P-G)" selected as the Fault Type, while the Transformer would have "No fault" selected.

19. Normal Clearing

A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection system.[5]

C. Outage Initiation Codes

The Outage Initiation Codes describe *where* an Automatic Outage was initiated on the power system.

1. Element-Initiated Outage

An Automatic Outage of an Element that is initiated on or within the Element that is outaged.

2. Other Element-Initiated Outage

An Automatic Outage of an Element that is initiated by another Element and not by the Element that is outaged.

3. AC Substation-Initiated Outage

An Automatic Outage of an Element that is initiated on or within AC Substation facilities.

4. AC/DC Terminal-Initiated Outage

An Automatic Outage of an Element that is initiated on or within AC/DC Terminal facilities.

5. Other Facility-Initiated Outage

An Automatic Outage that is initiated on or within other facilities. "Other facilities" include any facilities not includable in any other Outage Initiation Code. (Note: An Automatic Outage initiated on a Transformer that is *not* an Element is considered an AC Substation or an AC/DC Terminal-Initiated Outage since the Transformer would be considered part of an AC Substation or AC/DC Terminal.)

<u>Outage Initiation Code Examples</u>

1. A Transformer which is an Element is outaged. Is its outage an Element-Initiated Outage or a Substation-Initiated Outage? It depends. If the outage initiated on or within the Element (e.g., an internal fault or a cracked insulator that caused a fault), the outage is Element-Initiated, even though the Transformer is in a Substation. However, if the Transformer outage was not due to the Transformer itself but due, for example, to a failed circuit breaker, it is Substation-Initiated.
2. An AC Circuit which is an Element has an outage that was initiated by a non-Element AC Circuit. The Element outage is Other Facility-Initiated.
3. An AC Circuit Outage was initiated by an Element Transformer outage. The AC Circuit Outage is Other Element-Initiated.

[5] This definition is in the current NERC *Glossary of Terms Used in Reliability Standards*.

D. Outage Mode Codes

The Outage Mode Code describes whether an Automatic Outage is related to other Automatic Outages.

1. Single Mode Outage

An Automatic Outage of a single Element which occurred independent of any other outages (if any).

2. Dependent Mode Initiating Outage

An Automatic Outage of a single Element that initiates one or more subsequent Element Automatic Outages.

3. Dependent Mode Outage

An Automatic Outage of an Element which occurred as a result of an initiating outage, whether the initiating outage was an Element outage or a non-Element outage. (Note: to re-emphasize, a Dependent Mode Outage must be a result of another outage.)

4. Common Mode Outage

One of two or more Automatic Outages with the same Initiating Cause Code and where the outages are not consequences of each other and occur nearly simultaneously (i.e., within cycles or seconds of one another).

5. Common Mode Initiating Outage

A Common Mode Outage that initiates one or more subsequent Automatic Outages.

Dependent Mode and Common Mode Outage Examples

1. A Dependent Mode Outage involves two outages, but one of the outages can be a non-Element outage. Therefore, not all Dependent Mode Outages will have an associated Dependent Mode Initiating Outage. If the initiating outage is one of the four defined Elements, that outage will be a Dependent Mode Initiating Outage, and the resulting second Element outage will be a Dependent Mode Outage. For example, suppose a 500 kV AC Circuit is outaged as a result of a 500/230 kV Transformer outage. The AC Circuit outage is a Dependent Mode Outage, and the Transformer outage is a Dependent Mode Initiating Outage. However, if an outage is not initiated by an Element, it will not have an associated Dependent Mode Initiating Outage. If the Transformer in the previous example had been a 345/138 kV Transformer and the AC Circuit a 345 kV circuit, the Transformer would not be an Element and, therefore, the AC Circuit outage would not have an associated Dependent Mode Initiating Outage. The AC Circuit outage would be classified as a Dependent Mode Outage since it was the result of a non-Element outage.
2. A Common Mode Outage involves the two outages, but unlike a Dependent Mode Outage, both outages must be Elements. In addition, one outage must not cause the second outage to occur; i.e., the two outages are not consequences of each other. In addition, they must occur nearly simultaneously. As an example, suppose that lightning strikes two AC Circuits in the same right of way (but not

on a common structure) and both circuits are outaged nearly simultaneously. Assume no further outages occur. Both are Common Mode Outages. Now assume the same scenario with a slight difference: one AC Circuit clears normally, the second AC Circuit does not, and there is a circuit breaker failure, resulting in the outage of a third AC Circuit. The first AC Circuit outage is a Common Mode Outage. The second AC Circuit outage is a Common Mode Initiating Outage, with the third AC Circuit outage a Dependent Mode Outage.

E. Cause Codes Types

1. Initiating Cause Code

The Cause Code that describes the initiating cause of the outage.

2. Sustained Cause Code

The Cause Code that describes the cause that contributed to the longest duration of the outage. Momentary Outages do not have a Sustained Cause Code.

Initiating and Sustained Cause Code Examples

Suppose a lightning strike on an AC Circuit that should have cleared normally becomes a Sustained Outage because of breaker failure. “Lightning” is the Initiating Cause Code and “Failed AC Substation Equipment” is the Sustained Cause Code.

To illustrate the meaning of the phrase “contributed to the longest duration” in the definition above, suppose that lightning caused a conductor to break (“Failed AC Circuit Equipment”) and that the breaker for the circuit also failed (“Failed AC Substation Equipment’). This example has two possible Sustained Outage Cause Codes, and the one to select is the one that contributed to the longest duration. If the conductor was repaired before the circuit breaker, then “Failed AC Substation Equipment” is the Sustained Cause Code since the circuit breaker outage contributed to the longest duration.

Special Exception for 2008 Reporting: For reporting in 2008, Transmission Owners should supply both the Initiating and Sustained Cause Codes if they have them available. However, if both Cause Codes are not available, at least one Cause Code, either Initiating or Sustained, must be supplied for a Sustained Outage. (Momentary Outages still must have their Initiating Cause Code reported.) As an example, suppose a TO only has the Initiating Outage Cause Code available to it for Sustained Outages. The Initiating Cause Code would be entered for each outage, and the appropriate Sustained Cause Code would be “Unavailable.” On the other hand, suppose only a Sustained Cause Code is available. Sustained Outages would then have their Initiating Outage Codes reported as “Unavailable.” The “Unavailable” code will be deleted in 2009 when TOs are expected to have both Initiating and Sustained Cause Codes available.

F. Cause Codes

1. Weather, excluding lightning

Automatic Outages caused by weather such as snow, extreme temperature, rain, hail, fog, sleet/ice, wind (including galloping conductor), tornado, microburst, dust storm, and flying debris caused by wind.

2. Lightning

Automatic Outages caused by lightning.

3. Environmental

Automatic Outages caused by environmental conditions such as earth movement (including earthquake, subsidence, earth slide), flood, geomagnetic storm, or avalanche.

4. Contamination

Automatic Outages caused by contamination such as bird droppings, dust, corrosion, salt spray, industrial pollution, smog, or ash.

5. Foreign Interference

Automatic Outages caused by foreign interference from such objects such as an aircraft, machinery, a vehicle, a train, a boat, a balloon, a kite, a bird (including streamers), an animal, flying debris not caused by wind, and falling conductors from one line into another. Foreign Interference is not due to an error by a utility employee or contractor. Categorize these as "Human Error."

6. Fire

Automatic Outages caused by fire or smoke.

7. Vandalism, Terrorism or Malicious Acts

Automatic Outages caused by intentional activity such as shot conductors or insulators, removing bolts from structures, and bombs.

8. Failed AC Substation Equipment

Automatic Outages caused by the failure of AC Substation; i.e., equipment "inside the substation fence" including Transformers and circuit breakers but excluding Protection System equipment. Refer to the definition of "AC Substation."

9. Failed AC/DC Terminal Equipment

Automatic Outages caused by the failure of AC/DC Terminal equipment; i.e., equipment "inside the terminal fence" including PLC (power-line carrier) filters, AC filters, reactors and capacitors, Transformers, DC valves, smoothing reactors, and DC filters but excluding Protection System equipment. Refer to the definition of "AC/DC Terminal."

10. Failed Protection System Equipment

Automatic Outages caused by the failure of Protection System equipment. Includes any relay and/or control misoperations *except* those that are caused by incorrect relay or control settings that do not coordinate with other protective devices. Categorize these as "Human Error".

11. Failed AC Circuit Equipment

Automatic Outages related to the failure of AC Circuit equipment, i.e., overhead or underground equipment "outside the substation fence." Refer to the definition of "AC Circuit."

12. Failed DC Circuit Equipment

Automatic Outages related to the failure DC Circuit equipment, i.e., overhead or underground equipment "outside the terminal fence." Refer to the definition of "DC Circuit." However, include the failure of a connecting DC bus within an AC/DC Back-to-Back Converter in this category.

13. Vegetation

Automatic Outages (both Momentary and Sustained) caused by vegetation, with the exception of the following exclusions which are contained in FAC-003-1:

1. Vegetation-related outages that result from vegetation falling into lines from outside the right of way that result from natural disasters shall not be considered reportable with the Vegetation Cause Code. Examples of disasters that could create non-reportable Vegetation Cause Code outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods, and
2. Vegetation-related outages due to human or animal activity shall not be considered reportable under the Vegetation Cause Code. Examples of human or animal activity that could cause a non-reportable Vegetation Cause Code outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Outages that fall under the exclusions should be reported under another Cause Code and not the Vegetation Cause Code.

14. Power System Condition

Automatic Outages caused by power system conditions such as instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations (e.g., an abnormal terminal configuration due to existing condition with one breaker already out of service).

15. Human Error

Automatic Outages caused by any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the Transmission Owner will be identified and reported in this category. Also, any human failure or interpretation of standard industry practices and guidelines that cause an outage will be reported in this category.

16. Unknown

Automatic Outages caused by unknown causes should be reported in this category.

17. Other

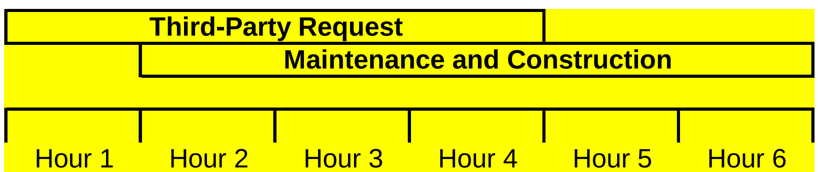
Automatic Outages for which the cause is known; however, the cause is not included in the above list.

18. Unavailable

Use for Sustained Outages for which either the Initiating or Sustained Cause Codes are unavailable to the Transmission Owner. If a Transmission Owner uses this code for Sustained Outages, it should be used on only *one* type of Cause Code (Initiating or Sustained), whichever is unavailable. If during 2008, both Cause Codes become available to the Transmission Owner, stop using "Unavailable." The "Unavailable" code will be withdrawn in 2009.

G. Planned Outage Cause Codes

If a Planned Outage was conducted for two reasons, record the Cause Code that contributed to the longest duration. For example, if an outage is 6 hours in duration and was taken to comply with a third-party request (which took 4 hours) as well as maintenance and construction (which took 5 hours), record the outage as Maintenance and Construction. See the diagram below.



1. Maintenance and Construction

Use for Planned Outages associated with maintenance and construction of electric facilities, including testing. This includes requests from any entity that is defined in the NERC Functional Model.[6]

2. Third-Party Requests

Use for Planned Outages that are taken at the request of a third party such as highway departments, the Coast Guard, etc.

3. Other Planned Outage

Use for Planned Outages for reasons not included in the above list, including human error.

[6] The Functional Model is available at http://www.nerc.com/page.php?cid=2|247|108. As an example, an outage is requested by a Generation Operator for purposes of completing an interconnection of its facilities would be classified in the Maintenance and Construction category. A Load-Serving Entity which requests an outage to make repairs to its substation would also be reported in this category.

H. Operational Outage Cause Codes

1. Emergency

Use for Operational Outages that are taken for the purpose of avoiding risk to human life, damage to equipment, damage to property, or similar threatening consequences.

2. System Voltage Limit Mitigation

Use for Operational Outages taken to maintain the voltage on the transmission system within desired levels (i.e., voltage control).

3. System Operating Limit Mitigation, excluding System Voltage Limit Mitigation

Use for Operational Outages taken to keep the transmission system within System Operating Limits, except for System Voltage Limit Mitigation. The term "System Operating Limit" is defined in the NERC *Glossary of Terms Used in Reliability Standards* and is excerpted below.

> "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:
>
> 1. Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
> 2. Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
> 3. Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
> 4. System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). "
>
> Do not include actions in the last category (System Voltage Limits) since this is included in the previous "System Voltage Limitation" code.

4. Other Operational Outage

Use for Operational Outages for reasons not included in the above list, including human error.

Appendix 3. Summary of Phase II Comments and Responses

Appendix 3, which follows, is a stand-alone report.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Summary of Phase II TADS Comments and Responses

September 11, 2008

to ensure the reliability of the bulk power system

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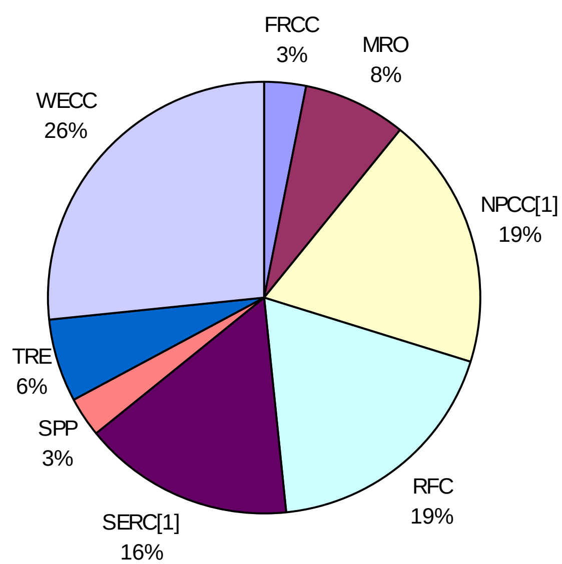
Table of Contents

1 Introduction

1.1 Who Commented

The April 30, 2008 letter from Mr. David Nevius of NERC requesting comments on the Phase II preliminary TADS report and Manual resulted in comments from 49 entities – 44 Transmission Owners (TOs) and five other entities. The 44 Transmission Owner responses represented a total of 63 registered NERC Transmission Owners and one unregistered Canadian TO, AltaLink Management, which is voluntarily submitting Phase I TADS data. The identification of the TOs that commented is shown on Table 1 on the next page. The distribution of responding TOs per NERC region is depicted on Figure 1 below. The response rate by region is shown on Table 2.

Figure 1
Distribution of Responding TOs by NERC Region



[1] Includes total registered TOs represented by pseudo NERC IDs for National Grid (NPCC) and Southern Transmission Company (SERC).

The five other entities that provide comments are listed below:

1. The Energy Information Administration (EIA)
2. The Independent Electricity Operator (IESO), which is the Transmission Operator for the Ontario province
3. The National Electrical Manufacturers Association (NEMA)
4. Separate comments came from different Reliability*First* Corporation staff. For this report, their responses will be combined.
5. WECC submitted comments on behalf of their Reliability Subcommittee and their Reliability Performance Evaluation Work Group.

All materials related to the request for comments, including the individual comments, are posted at http://www.nerc.com/filez/tadstf.html.

Table 1
Transmission Owners that Provided Phase II TADS Comments

NERC ID	Company Name	Country	Region
PSD00002	AltaLink Management Ltd. **[1]**	Canada	WECC
NCR00682	American Electric Power Service Corp **[2]**	US	RFC
NCR04006	American Electric Power Service Corp **[2]**	US	TRE
NCR01056	American Electric Power Service Corporation **[2]**	US	SPP
NCR00685	American Transmission Company	US	RFC
NCR05016	Arizona Public Service Company	US	WECC
NCR00688	Atlantic City Electric Company (ACE) **[3]**	US	RFC
NCR00689	Baltimore Gas & Electric Company	US	RFC
NCR05032	Bonneville Power Administration	US	WECC
NCR04028	CenterPoint Energy	US	TRE
NCR00729	Commonwealth Edison Company **[4]**	US	RFC
NCR07044	Connecticut Light & Power **[5]**	US	NPCC
NCR05123	Cowlitz County PUD No. 1	US	WECC
NCR04037	CPS ENERGY	US	TRE
NCR00752	Delmarva Power **[3]**	US	RFC
NCR01214	Dominion Virginia Power - Transmission	US	RFC
NCR01219	Duke Energy Carolinas **[6]**	US	SERC
NCR00761	Duke Energy Corp. **[6]**	US	RFC
NCR10242	Dynegy Arlington Valley, LLC	US	WECC
NCR01234	Entergy	US	SERC
NCR01249	Georgia Transmission Corporation	US	SERC
NCR07109	HydroOne Networks	Canada	NPCC
NCR05191	Idaho Power Company	US	WECC
NCR10192	ITC Midwest **[7]**	US	MRO
NCR00803	ITC Transmission **[7]**	US	RFC
NCR01107	Kansas City Power & Light	US	SPP
NCR01003	Manitoba Hydro	Canada	MRO
PSD00004	National Grid **[8]**	US	NPCC
NCR01018	Nebraska Public Power District	US	MRO
NCR07161	New York Power Authority	US	NPCC
NCR02611	Northern Indiana Public Service Company	US	RFC
NCR07178	Nova Scotia Power Inc.	Canada	NPCC
NCR04109	Oncor Electric Delivery	US	TRE
NCR05299	Pacific Gas and Electric Company	US	WECC
NCR05304	PacifiCorp	US	WECC
NCR08025	PECO Energy **[4]**	US	RFC
NCR00881	Potomac Electric Power Company (PEPCO) **[3]**	US	RFC
NCR00063	Progress Energy - Florida	US	FRCC
NCR01298	Progress Energy Carolinas	US	SERC
NCR07203	Public Service Company of New Hampshire **[5]**	US	NPCC
NCR05368	Sacramento Municipal Utility District	US	WECC
NCR05372	Salt River Project Agricultural Improvement and Power District	US	WECC
NCR05377	San Diego Gas & Electric	US	WECC
PSD00001	Southern Company Transmission **[9]**	US	SERC
NCR05402	Southwest Transmission Cooperative, Inc.	US	WECC
NCR00073	Tallahassee, City of	US	FRCC
NCR01151	Tennessee Valley Authority	US	SERC
NCR10102	Tri-State Generation and Transmission Association, Inc. **[10]**	US	MRO
NCR10030	Tri-State Generation and Transmission Association, Inc. - Reliability **[10]**	US	WECC
NCR05461	Western Area Power Administration - Desert Southwest Region	US	WECC
NCR05464	Western Area Power Administration - Rocky Mountain Region	US	WECC
NCR05465	Western Area Power Administration - Sierra Nevada Region	US	WECC
NCR05467	Western Area Power Administration - Upper Great Plains Region **[11]**	US	WECC
NCR01036	Western Area Power Administration- Upper Great Plains East **[11]**	US	MRO
NCR07232	Western Massachusetts Electric Company **[5]**	US	NPCC

Table 1 (cont'd)
Transmission Owners that Provided Phase II TADS Comments

No.	Table 1 Notes
[1]	AltaLink is not a NERC-registered TO, but it is voluntarily providing Ph I TADS data for Automatic Outages. It was assigned a pseudo NERC ID for TADS. See the Manual, Section 1.9, for a description of pseudo NERC IDs.
[2]	Comments from American Electric Power were attributed to three AEP NERC IDs.
[3]	Comments from Pepco Holdings, Inc. were attributed to three of its affiliates: Atlantic City Electric Company, Delmarva Power, and Potomac Electric Power Company.
[4]	Comments from Exelon were attributed to two affiliates: Commonwealth Edison and PECO Energy.
[5]	Comments from Northeast Utilities were attributed to three of its affiliates: Connecticut Light & Power, Public Service Company of New Hampshire, and Western Massachusetts Electric Company.
[6]	Comments from Duke Energy were attributed to two Duke NERC IDs.
[7]	Comments from ITC Holdings were attributed to two affiliates: ITC Midwest and ITC Transmission.
[8]	National Grid has a pseudo NERC ID and its comments were attributed to six registered NERC TOs – see http://www.nerc.com/docs/pc/tadstf/NERC_ID_Exceptions_for_TADS_02_18_2008.pdf. Thus, each National Grid response has a "6" instead of a "1" weight. See the Manual, Section 1.9, for a description of pseudo NERC IDs.
[9]	Southern Company Transmission has a pseudo NERC ID and its comments were attributed to five registered NERC TOs – see http://www.nerc.com/docs/pc/tadstf/NERC_ID_Exceptions_for_TADS_02_18_2008.pdf. Thus, each Southern Company Transmission response has a "5" instead of a "1" weight. See the Manual, Section 1.9, for a description of pseudo NERC IDs.
[10]	Comments from Tri-State Generation and Transmission Association were attributed to two Tri-State NERC IDs.
[11]	Comments submitted by WAPA Upper Great Plains Region were attributed to two WAPA NERC IDs.

Table 2
Responses from Reporting TOs by Region[1]

Region	No. of Reporting TOs with Ph II TADS Comments	Total Reporting TOs	Response Rate
FRCC	2	14	14.3%
MRO	5	24	20.8%
NPCC [1]	12	26	46.2%
RFC [1]	12	27	44.4%
SERC [1]	10	24	41.7%
SPP	2	14	14.3%
TRE	4	12	33.3%
WECC	17	63	27.0%
TOTAL	**64**	**204**	**31.4%**

[1] Includes total registered TOs represented by pseudo NERC IDs for National Grid (NPCC), First Energy (RFC), and Southern Transmission Company (SERC).

[1] Reporting TOs are TOs that own one or more TADS Elements. This table is based upon Phase I reporting TOs – it has all reporting U.S. TOs (who must report Phase I data) and all reporting non-U.S. TOs who have indicated that they will voluntarily report Phase I data.

1.2 TO Response Statistics

Most TOs provided answers to the seven questions we asked. Characterizing the responses was challenging – while we received primarily "Yes" or "No" responses, many responses were qualified, and for those we categorized them as "Part." As an example, if someone stated that they collected Phase II TADS data except for transformer outages, we labeled that as a "Part" response to the first question that asked if outage data similar to Phase II TADS is currently being collected. In some cases, the commenter did not answer the question, so we characterized those responses as "Undetermined."

- Our process for categorizing each responding TO's response had two steps: (i) an initial assessment was done by the TF secretary followed by (ii) a review by TF members who were assigned to specific TOs and who suggested corrections. In some cases, a fair amount of judgment was required for characterizing responses.

The resulting inventory of responses is shown on Table 3 below. The first line shows the number of responses and the second shows the percentage of responses to each question.[2] As shown on the table, we sub-divided question 2 and 3 into several parts.

Table 3
Summary of TO Responses to the Questions in Section B of the Request for Comments

	Question	Yes	Part	No	Und
1.	Currently collecting Non-Automatic outage data?	35	19	9	1
		55%	30%	14%	2%
2.a	Is the data reasonable?	18	2	37	7
		28%	3%	58%	11%
2.b	Is the data obtainable?	63	0	0	1
		98%	0%	0%	2%
3.a	Is the 30 min. Planned Outage exclusion appropriate?	37	4	19	4
		58%	6%	30%	6%
3.b	Should a TO record all outage times to determine which outages to exclude?	10	0	11	43
		16%	0%	17%	67%
3.c	Should a TO's supporting data for 30 min. exclusions be part of NERC's data review?	2	0	41	21
		3%	0%	64%	33%
3.d	Does the 30 min. exclusion reduce the reporting burden?	16	0	30	18
		25%	0%	47%	28%
4.	Are the metrics approporiate?	21	8	32	3
		33%	13%	50%	5%
5.	Is a 5-year data retention appropriate?	49	1	12	2
		77%	2%	19%	3%
6.	Is the implememntation schedule reasonable?	34	0	24	6
		53%	0%	38%	9%
7.	Are their ambiguities in Manual?	16	0	44	4
		25%	0%	69%	6%

[2] A total of 64 TO responses were tabulated for each question.

We also tabulated four "paired" question responses for the question pairs shown on Table 4. We felt the paired questions allowed us to better examine responses that one would expect to be correlated.

As an example of interpreting the paired response table, consider the first paired response: Of the 18 who responded "Yes" to the question of whether the data requested in Phase II TADS is reasonable, 15 are currently collecting similar data. Looking again at the first paired response shows that of the 35 TOs that currently collect similar Phase II data (note that adding all "Yes" answers produces 35), only 18 felt that the data request was reasonable. This response was somewhat unexpected. We refer to these paired responses in Section 3 that examines the comments from TOs.

Table 4
Paired TO Question Responses
(Data = No. of Responses)

Data reasonable? (Q.2.a)	Currently collecting? (Q.1)			
Yes	Yes	Part	No	Und
18	15	2	1	0
Part				
2	2	0	0	0
No				
37	15	16	5	1
Und				
7	3	1	3	0

Data reasonable? (Q.2.a)	Metrics appropriate? (Q.4)			
Yes	Yes	Part	No	Und
18	14	3	0	1
Part				
2	1	0	1	0
No				
37	2	2	32	1
Und				
7	4	3	0	0

30 min Planned Outage exclusion OK? (Q. 3.a)	Reduce reporting burden? (Q.3.d)			
Yes	Yes	Part	No	Und
37	17	1	9	10
Part				
4	0	0	4	0
No				
19	1	0	15	3
Und				
4	0	0	0	4

Currently collecting? (Q.1)	Schedule reasonable? (Q.6)			
Yes	Yes	Part	No	Und
35	24	0	8	3
Part				
19	10	0	8	1
No				
9	0	0	9	0
Und				
1	0	0	0	1

2 Comments Resulting in Phase II TADS Changes

We made several changes to the Phase II TADS as a result of comments. These are summarized below:

1. In response to numerous comments expressing concern about the Phase II schedule, we delayed implementation by one-year. Phase II TADS will now require that all Transmission Owners who are also NERC members report their Non-Automatic Outages for calendar year 2010 by March 1, 2011 (i.e., Non-Automatic Outages from January 1, 2010 through December 31, 2010). See Section 3.1, pp. 7-8.
2. In response to concerns as to whether Phase II TADS data is a benefit to NERC, we recommended that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion. We also recommended that the benefits to NERC of Phase II be demonstrated after five years of data has been collected. This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan**.** Furthermore, we recommended that this demonstration be followed by re-approval of Phase II data collection by the Planning Committee and the Board of Trustees. See Section 3.2, pp. 8-10.
3. In response to Nebraska Public Power District's request that we add a "forced outage rate" metric, we declined to add their suggested formula as a general metric because it may be defined differently by different TOs. However, we will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric. See Section 3.6. p. 17
4. In response to National Grid's comment that TOs should be allowed to enter data in local time instead of Universal Coordinated Time (UTC) since webTADS has this capability, we will modify webTADS in the future to allow data to be entered in local time *if* it is entered via the graphical user interface (GUI). However, it will be converted to UTC and stored in webTADS in UTC. Bulk-loaded data entry must still be in UTC. We will clarify this in a future update of the Manual. See Section 3.9, p. 22.

3 Responses to Comments

We would first like to thank all those who took the time to submit comments. The TF greatly appreciates the input it received, and as a result the Phase II proposal will be much better.

The sections that follow address common topics. In each section, we provide a single response to similar comments, and we also address selected individual comments.

3.1 The Phase II Schedule

In response to numerous comments requesting a delay in the start of data collection for Phase II data, we made a change to the schedule for Phase II implementation. Several TOs recommended delaying Phase II implementation (previously set for January 1, 2009) by at least a year and stated that the proposed timetable was too aggressive for the in-house systems changes needed to meet the January 1, 2009 date.[3] In total, 38% of the responding TOs felt the implementation schedule was not reasonable.

Since we can delay the start of data collection until January 1, 2010 without disturbing the expected mandatory EIA Schedule 7 reporting requirement that would require the reporting of 2010 calendar year data in 2011, we agree with delaying the TOs data collection start date by one year to January 1, 2010. Therefore, we will require that all Transmission Owners who are also NERC members report their Non-Automatic Outages for calendar year 2010 by March 1, 2011 (i.e., Non-Automatic Outages from January 1, 2010 through December 31, 2010).[4]

A one-year implementation delay will allow Transmission Owners to have adequate time to develop the necessary software systems for Non-Automatic Outage reporting.

- We are aware that Phase II will make Transmission Owners responsible for Non-Automatic Outage reporting, and that some of the Non-Automatic Outage data required in Phase II may be logged by Transmission Operators (TOPs) or Reliability Coordinators (RCs).[5] For those Transmission Owners that are not Transmission Operators, an agreement is in place that permits the Transmission Operator to operate the Transmission Owner's facilities. These agreements normally require coordination and cooperation between the parties. Therefore, Transmission Owners will need to coordinate with their TOP and their RC to develop the most efficient and cost-effective method of collecting complete Non-Automatic Outage data for reporting to NERC by a single entity.

We will contract with OATI for modification of webTADS to accommodate Non-Automatic Outage reporting. The schedule that we will pursue with OATI for Phase II is as shown on the next page. OATI concurred with this schedule in direct discussions with the TF.

[3] AltaLink Management, American Transmission Company, BPA, CenterPoint Energy, Exelon, Northeast Utilities, CPS Energy, Dominion, ITC Holdings, National Grid, Northern Indiana Public Service Company, Progress Energy-Florida, Progress Energy-Carolina, and TVA.
[4] U.S. TOs must also submit Automatic Outage data for calendar year 2010 on March 1, 2011.
[5] WAPA-Upper Great Plains Region asked whether NERC could coordinate TADS with Reliability Coordinators. Such a coordination approach would not be feasible due to different RC systems.

Table 5
Phase II webTADS Schedule

Target Date	Phase II Activity
Late Nov. 2008	NERC completes Phase II webTADS requirements and submit to OATI.
Feb. 1, 2009	NERC will publish final specifications for data input and error checking so that TOs may use the specifications to modify their data collection systems.
Feb 1-July 1, 2009	OATI will complete changes to webTADS for Phase II, including system testing with dummy data.
July 1-Dec. 1, 2009	NERC and OATI will conduct Phase II webTADS training. We recognize that some TOs will have different personnel entering Non-Automatic Outage data into webTADS, and therefore we have allowed a long training period.
July 1-Dec. 31, 2009	"Dry run" data entry permitted into webTADS by TOs for any part of their actual or dummy 2009 data. Any 2009 Phase II data which a TO enters will not be retained in webTADS after December 31, 2009.

The last step – a Phase II dry-run period – is designed to allow TOs that will be bulk loading Phase II TADS data to verify the compatibility of their in-house data extraction and transfer protocols with webTADS data input requirements using actual or dummy 2009 data. TOs that will not be bulk loading webTADS data may also test their ability to input actual or dummy 2009 data. Dry-run testing is completely optional, but we believe that TOs who avail themselves of this option will be better prepared for 2010 implementation.

3.2 Reasonableness of the Phase II Data Request

We received numerous comments, some lengthy, that we had not adequately demonstrated benefits that exceeded the burden of collecting and submitting Non-Automatic Outage data to NERC. These came in response to many of the questions that we asked, including whether the data being requested was reasonable (37 of 64 responding TOs, or 58%, said "No") and whether the metrics were appropriate (50% of responding TOs said "No").[6] Two TOs (Baltimore Gas & Electric and TVA) felt that the Emergency Outage data was reasonable, but not the Planned Outage data. The remaining TOs responded as follows (see Table 3): 18 (28%) say the requested Phase II data *was* reasonable, and 7 (11%) responses were undetermined.

We further analyzed the responses of the 37 TOs[7] that stated that Phase II was unreasonable. Many provided several reasons. Table 6 on the next page is a summary of *why* they felt the data was unreasonable.

[6] WECC also opposed both Phase II and the metrics.
[7] The 37 TOs who said the data requested was not reasonable are: American Transmission Co., Arizona Public Service, BPA, CenterPoint Energy, Exelon (representing two TOs), CPS Energy, Dominion, Duke ((representing two TOs), Idaho Power, ITC Holdings (representing two TOs), Manitoba Hydro, National Grid (representing six TOs), Nova Scotia Power, PG&E, PacifiCorp, SMUD, Salt River Project, Southern Company Transmission (representing five TOs), Tallahassee, Tri-State G&T (representing two TOs), WAPA- DSR, WAPA-RMR, and WAPA-UGPR (representing two TOs).

Table 6
Reasons that 37 TOs Objected to the Phase II Data Request

Why requested Ph II data is unreasonable	No. of TOs	Percent*
No proven reliability benefit	34	92%
High cost of collecting	31	84%
Implementation schedule too short	9	24%
Data may lead to new standards	7	19%
Collection may lead to behavior that degrades reliability or safety	9	24%
Data is not comparable	8	22%

*based on 37 TOs who said requested Phase II data is unreasonable

Some TOs provided separate statements explaining their Phase II objections.[8] BPA and ITC Holdings suggested performing a cost/benefit analysis to determine whether Non-Automatic Outage data collection should be implemented.

While most TOs questioned the long-term reliability benefits that might be derived from Phase II data, two TOs did not see how the Phase II data would be useful towards improving *current day-to-day* reliability.[9] We disagree that the collection of historic Non-Automatic Outage data will have no direct impact on day-to-day reliability. Analysis of historic Planned Outages could improve scheduled outage planning accuracy and therefore day-to-day reliability.

There were some unexpected results. Most responding TOs (35 of 64 responding TOs, or 55%) *already collect* similar Non-Automatic Outage data. Per Table 4, of the 35 responding TOs that already collected similar data, 15 said the data request is unreasonable. Several of those TOs already have in-house software programs, but none said they currently collected it for reliability analysis.[10]

In response to whether we have offered sufficient rationale for Phase II TADS, we point to Section 2.3 of the preliminary Phase II report which cited several reasons for collecting Non-Automatic Outage data:

1. Non-Automatic Outage data will complement Phase I Automatic Outage data, resulting in our ability to capture almost all transmission Element outages.
2. Complete transmission outage information may influence NERC Reliability Standards development.
3. Complete transmission outage information could allow for improved system analysis by bridging gaps between the operating environment and planning assumptions.
4. For U.S. Transmission Owners who are subject to EIA reporting requirements, the reporting of Non-Automatic Outages to NERC could avoid a duplicative reporting requirement to EIA. (We discuss this last reason in Section 3.3 below.)

[8] CenterPoint Energy, CPS Energy, Dominion, Duke Energy, Nova Scotia Power, and Northeast Utilities
[9] Georgia Transmission Company and Southern Company Transmission
[10] Examples include National Grid, TVA (who had decided to suspend the future collection of Non-Automatic outage data that it currently collects) and Duke Energy (who is not currently collecting Non-Automatic outage data, but who has software under development for its collection beginning in 2009).

With respect to the third reason listed above, we provide additional support below which we will add to the final Phase II report:

- From a planning perspective, if planned outages are not properly accounted for in the planning of the system, insufficient facilities may be built, making day-to-day reliability worse.[11] Several TPL standards (TPL-002-0, TPL-003-0, and TPL-004-0) have a requirement that planned outages be explicitly considered. In TPL-002-0, this is found in R1.3.12:

  > "Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

  Historical Planned Outage data could help Transmission Planners with this requirement.

To the four reasons listed above, the TF will add a fifth reason to our final Phase II report:

- No Reliability Standard or NERC rule (in NERC's *Rules of Procedure*) requires the systematic recording of historic system topology for the purpose of analyzing events. TADS will begin to fill this need by collecting both Automatic and Non-Automatic Outage data. Since we only require the submission of TADS data annually, we recognize that the submission of TADS data into webTADS may not occur until months after an event. The requirement to collect TADS outage data means that TOs could, by special request from NERC, provide outage data if required to help NERC analyze an event, and the fact that such data will be entered into a structured TADS database will be helpful.

Finally, we recommend that the Planning Committee and the Board of Trustees seriously consider the objections expressed by the TOs to the Phase II expansion. In addition, since the reasonableness of Phase II cannot *presently* be demonstrated with hard facts, we recommend that Phase II benefits to NERC be demonstrated after five years of data has been collected.[12] This demonstration should be conducted by the Planning Committee, and the Planning Committee should include this task in its work plan. Furthermore, we recommend that this demonstration be followed by re-approval of Phase II data collection by the Planning Committee and the Board of Trustees. The five-year data collection period will conclude with 2014 data, which will be collected in 2015. The demonstration of Phase II benefits should be performed on or before August 15, 2015 to allow sufficient time for Planning Committee and Board of Trustees action.

[11] Tallahassee said "The way to improve reliability is to put more wire in the air in areas that show consistent contingency problems." We agree, but getting this result requires a proper representation of the system by transmission planners. If planners assume no Planned Outages at time of system peak, but our data shows otherwise, planners may in fact be able justifiably "put more wire in the air."

[12] Many TOs suggested that we analyze the historic ECAR data to determine it usefulness. ECAR data collection ended in 2005, and while the data was made available to TOs for over 20 years, the use that each TO made of that data would be difficult to determine.

3.3 EIA Form 411, Schedule 7

As explained in Section 2.4 of the preliminary Phase II report, EIA has agreed to leave Schedule 7 collection voluntary for now; mandating Schedule 7 will be re-addressed in the Electricity 2011 project, which will take up the re-authorization of EIA data collection forms, including Form 411.[13]

We expect EIA to mandate that NERC provide Schedule 7 data submittals in 2011, which will require that NERC submit 2010 data to EIA in 2011. NERC plans to use TADS to comply with this expected future requirement. EIA will not address the 2011 filing requirement of 2010 data until early 2010, making there final decision in the fall of 2010. Since NERC cannot ramp up a mandatory collection with only months notice, the start-up schedule described in Section 3.1 needs to be followed.

- Some TOs questioned why we are requesting additional detailed Phase II data over what Schedule 7 requires.[14] First, we believe that the additional data we are requesting will allow NERC to produce metrics with the detail that is consistent with Phase I. Second, we also believe that the additional detail (e.g., listing individual outages with start times and durations) would be part of the normal records kept by a TO to develop aggregated Schedule 7 data. Finally, we added several cause codes that we felt would provide value to NERC, even though they are not required by EIA. For example, we have three cause codes for Planned Outages, while EIA does not have any.

- WECC and several WECC TOs provided this comment:[15]

  > "During the time period in which DOE has allowed the Schedule 7 data collection to remain voluntary, that NERC and DOE work together to develop reasoning and worthwhile uses for the NERC wide collection of the scheduled outage data."

  EIA, federal users, and NERC have had discussions on the intended use of Non-Automatic Outage data. We will continue our collaborative discussions with EIA on the defining the benefits of Phase II.

- In their transmittal letter of WECC's comments, WECC states:

  > "Collectively we are very concerned about NERC's effort to gather this data on behalf of the Department of Energy (DOE) when the DOE would not otherwise have access to this information."

  To clarify, EIA *can* mandate the collection of data by NERC for EIA's use. EIA decided *not* to request access to detailed TADS data, such as individual Element outage start times, durations, and cause codes. As discussed in the preliminary Phase II report, EIA's decision to forego access to Confidential Energy Infrastructure Information (which describes most of TADS individual outage data) was based upon their concerns about maintaining the confidentiality of such data.

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[13] Schedule 7 has been voluntary since 2006. Its collection was primarily triggered by the August 14, 2003 blackout and the realization that the federal government did not have transmission reliability data. EIA wanted to make Schedule 7 mandatory beginning in 2008.
[14] American Transmission Company, CenterPoint Energy, and CPS Energy
[15] Arizona Public Service, Idaho Power, SMUD, Salt River Project, and WAPA-Desert Southwest Region

3.4 Definition of Planned Outage and Operational Outage

TVA, Hydro One, and IESO commented that the term "advanced notice" is ambiguous and suggested that we adopt a time frame for that term. Baltimore Gas & Electric and Pacific Gas and Electric (PG&E) asked that a specific time frame for "deferred" be adopted.

The relevant language of the definitions being questioned is provided below:

- <u>Planned Outage</u>: A Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred.
- <u>Operational Outage</u>: A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property), or to maintain the system within operational limits, and that cannot be deferred.

We do not believe that these definitions need to include a reference to a specific time frame. TOs may have their own individual time frames, some of which may be specific to a situation. For example, the time frame that constitutes an emergency to protect equipment from damage will be TO-specific and equipment-specific.

The way to determine the category for a Non-Automatic Outage is to first examine the *purpose* of the outage. If its purpose was for "maintenance, construction, inspection, testing, or "planned activities by third parties," it was a Planned Outage. If its purpose was "avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits," it was an Operational Outage.

Second, examine the *timing* of the outage. If it was prescheduled with advanced notice to parties involved with the outage *and* if there was discretion with respect to the outage's actual scheduling, then it was a Planned Outage. If these timing factors are absent, then it was an Operational Outage.

3.5 30-minute Exclusion for Planned Outages

We received many thoughtful comments on the proposed 30-minute exclusion window for switching-related Planned Outages. We had proposed the following language in the definition of Planned Outage:

- "[Planned] Outages of TADS Elements of 30 minutes or less duration resulting from switching steps or sequences that are performed in preparation of an outage of another TADS Element are not reportable."

Our intent was to eliminate the reporting of "setup switching" or "restoration switching" outages that are not part of an intended Planned Outage. Per Table 3, although 58% of the responding TOs said the 30-minute exclusion was appropriate, only 25% said that the exclusion would reduce the reporting burden. A comment provided by the Sacramento Municipal Utility District (SMUD) captures this contradiction:

> "This is a reasonable exclusion time, do not remove. The exclusion based upon the 30 minute rule has minimal impact on the reporting time as the duration has to be calculated for each reported outage before the outages can be filtered for those that do not meet the exclusion time."

Some agreed with SMUD that the exclusion would have little or no noticeable impact on the reporting burden other than slightly reducing the volume of reported outages.[16] Still others said the exclusion would *increase* the reporting burden because it would not only require recording all outages, but it would additionally require determining which ones should be excluded because they are "setup switching" outages.[17] Tri-State G&T disagreed with the exclusion, noting that it "…will increase the burden on reporting while taking away from one of the main goals of the program" which is the collection of complete outage information. EIA agreed that the exclusion was reasonable, noting while they had set a one-hour exclusion for EIA Form 411, "[i]ndustry standards should be tighter." [18]

Two alternatives were suggested:

a. Record all outages (i.e., remove the 30-minute exclusion) but add a Planned Outage Cause Code or flag for "switching related outages."[19]

b. Do not report <u>any</u> Planned Outages that are 30 minutes or less, regardless of the reason. This would eliminate the need for a TO to determine whether the outage is a switching related outage which is required for the Planned Outage of another TADS Element.[20] Two TOs suggested a blanket one-hour instead of a 30-minute exclusion.[21]

The TF believes that most switching sequences take less than 30 minutes, and we reject the exclusion of all Planned Outages that are 30 minutes or less because of the loss of availability data.[22] While we are concerned with the potential for the 30 minute exclusion to increase reporting effort, we will leave the 30-minute exclusion as proposed and revisit it in the future as feedback from TOs warrants.

3.5.1 Supporting Data for the 30-minute Exclusion for Planned Outages

We also asked whether a TO's supporting data for determining the 30-minute exclusion should be part on NERC's data review. Only 3% of responding TOs said "Yes." Therefore, we will ***not*** require that TOs retain supporting data for determining its 30-minute exclusions for a NERC data review.

3.6 Phase II Metrics

As shown on Table 4, of the 37 responding TOs who said "No" on whether the data requested was reasonable, 32 also responded "No" on whether the metrics were appropriate. Most of the "No" responses to the metrics questioned how the data would be useful. Since many of those comments merely reiterated that the data being requested was reasonable, our response in Section 3.2 above will serve as our response to those metrics comments.

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[16] Baltimore Gas & Electric, Pepco Holdings, Cowlitz County PUD, CPS Energy, Entergy, Georgia Transmission Corporation, Southern Company Transmission, and Southwest Transmission Cooperative
[17] CenterPoint Energy, Dominion, ITC Holdings, NPPD, Oncor, Tallahassee, and TVA
[18] Other entities commented on the 30-minute exclusion: the ISEO and WECC supported the exclusion; Mr. Mitchell of Reliability*First* Corporation did not support it; Mr. Somayajula supported eliminating all outage reporting of switching steps, regardless of duration.
[19] Suggested by CenterPoint Energy and New York Power Authority
[20] Suggested by BPA, Oncor, and TVA
[21] Suggested by CPS Energy (to conform with ERCOT requirements) and Georgia Transmission Corporation (to conform with Schedule 7 requirements)
[22] Northeast Utilities said "Some circuits could take a couple of hours to completely deenergize." While we do not dispute the claim, we believe such occurrences are very rare.

We had several targeted comments that we respond to below:

- CenterPoint Energy said:

  "No [the proposed metrics are not appropriate]. The metrics will allow for trending of the values from year to year, but are not in themselves indicators of bulk power system reliability. There is also no indication within the Phase II Report if a directional change (up or down) in the trend of any of the Phase II TADS recommended planned outage metrics can indicate better or worse bulk power system reliability. EPRI did not recommend any metrics for planned outages for external benchmarking or regulatory purposes and specifically found no value in the total availability metric (APC) proposed in Phase II TADS."

- TVA said:

  "The proposed metrics are not appropriate because they can be misleading in analyzing the performance of a robust bulk power system. TVA has built its bulk power system for peak loads, and therefore, has an operating margin for "normal" (non-peak) operating conditions. This margin is used to perform maintenance and perform improvement projects which increase the reliability of the system. Most of the metrics for non-automatic outages could give a false impression of condition or risk without more specific knowledge. The bulk power system does not necessarily suffer since every bulk power line is not critical to daily operation."

We agree with CenterPoint and TVA that we have not tied any of the Non-Automatic Outage metrics specifically to bulk power system reliability. Our Phase II metrics were based upon the Phase I metrics. The following statement from Section 4 of the Phase I report dated September 26, 2007 also applies to Phase II metrics:

> "Given the richness of the data, the metrics described below can be computed for many data combinations. For example, one could calculate the metrics for each Cause Code, for each Outage Mode, for each Event Type Number, and for various combinations of these. We have not established a comprehensive set of uniform metric calculations since we expect that it will take some work with the data itself to tell us which combinations provide meaningful information."

We expect that the Phase II metrics to also evolve as we gather Phase II data and analyze it. Finally, the requirement we set in Section 3.2 to demonstrate the benefits of Phase II after five years of data collection should also demonstrate the benefits of the metrics as they exist at the time of that demonstration.

- Dynegy Arlington Valley said that radial circuit data such as circuit tying a generator into the system should be either excluded or tracked separately since its not part of the "integrated transmission system." The TF discussed radial circuits in Phase I and concluded that the Automatic Outage metrics of *all* circuits were of interest, and that the circuit's configuration (network or radial) was not relevant. We agree that the *consequences* of a network circuit outage will be different than a radial circuit outage, but the basic outage causes are the same. As an example of different consequences, if a radial circuit connecting a generator has an outage, a circuit outage means both the circuit *and* the generator are unavailable. So radial circuit availability can significantly impact the performance of the bulk power system.

- Duke Energy said the mean and median data provided in Phase I and II have little value. PG&E had a similar comment regarding the mean values. For Mean Time to Repair in Phase I, we are calculating a standard deviation and a confidence interval for Phase I data, and will do so for the Mean Element Planned Outage Time and Mean Element Operational Outage Time in Phase II data. We also believe that the median times add perspective to the mean times since one can easily tell if a few events affected the mean by comparing the two. We will emphasize this in our final Phase II report.
- PG&E stated that "availability and reliability metrics are most useful when applied at the individual circuit level." For each Element outage, we require a TO Element Identifier (see the Manual, Appendix 7, p. 8). Although TADS does not maintain a list of individual circuits, individual circuit performance could be calculated by a TO if the TO exports the data it submitted to webTADS for its own analysis.
- Several TOs had expressed concerns about certain "unintended consequences" regarding metrics.

- Southern Company Transmission said:

> "Trending planned outages could lead NERC to suggest standards which might limit Transmission Owners to certain "windows" of time and certain "lengths of duration" for maintenance to be performed. Doing so could possibly do more harm than good to the transmission system."

- PG&E said:

> "There is concern how TADS may ultimately be used to penalize transmission owners that are not meeting metric "averages." The TADS Phase II Preliminary Report states on p. 3 that "Trending of Non-Automatic Outage metrics *within* a Regional Entity may be useful, but comparisons *between* Regional Entities are inappropriate for the same reasons provided in the Phase I report." It further states that "correlations between Phase I Automatic Outages and Phase II Non-Automatic Planned Outages should be approached with caution." Despite these statements of caution (which PG&E supports), there still exists a concern that PG&E may have fines imposed on it if it is not meeting such "average" performance metrics relative to other utilities within the electric transmission system covered by NERC, as we may be providing reliable service to our customers, but still not be in the upper half of the statistical grouping."

We acknowledge Southern Company Transmission's and PG&E's concern that at some point the TADS data may be used to support a new Reliability Standard. However, the Reliability Standards process is a stakeholder-driven one, and unless the TADS data convincingly supports a new standard, it will not be approved by the stakeholders.

- CPS Energy said:

> "The metrics are not appropriate, since many proposed metrics have no real relevance to the goal of improving the reliability of the Bulk Electric

> System (BES). While such metrics could be viewed as "nice" for reports, the fear that many misrepresented metrics may actually lead towards tendencies to "improve metrics" by reducing maintenance outages could actually occur to the detriment of the BES."

We agree that the unintended consequence described by CPS Energy is a possibility for TOs that focus on the metrics as opposed to what needs to be done to improve reliability. Phase II metrics should not be the sole driver of actual maintenance practices. Maintenance practices should be based upon reliability considerations and good utility practice.

- Hydro One asked:

> "The TADS Phase II Preliminary Report recommends that planned outage performance not be compared among utilities. Does NERC intend to apply this approach to metrics that include the planned outage data?"

The metrics on an individual TO are the confidential performance metrics of that TO and will not be compared on a TO basis by NERC. See Section 5.3.3 of the Phase I report dated September 26, 2007.

- EIA stated the following:

> "EIA believes some of the metrics could be improved. The starting point for developing TADS was transmission outage information. However, the use of the word availability in the title suggests that the system might include additional information. This would include such metrics on both outage and equipment failure rates (protective system failure to open, to close, to operate, and protective system false operation rates). Other key information that needs to be linked with these metrics deal with the exposure (time and operations) associated with weather; that is, normal, adverse, and major storm disasters. In addition, EIA hopes that the restriction of only tracking events impacting power flows through designated points in the Phase II TADS will be expanded to address individual components or equipment that are outside of the set parameters of Phase II TADS, but which are linked into the high voltage transmission systems."

When Phase II is implemented, TADS will track the complete operational history of four classes of Elements that are ≥ 200 kV: AC Circuits, DC Circuits, Transformers, and AC/DC Back-to-Back Converters. These Elements are equivalent to the IEEE Standard 859[23] definition of a "component." There are various methods for defining a component. As an example, an AC Circuit can be subdivided into its constituent components of conductors, insulators, series compensation, etc. Our TADS definitions are very specific on what facilities are included or excluded in the definition of an Element, which is our lowest level of measuring performance. We could have gone to a lower equipment component level such as the approach used by the Canadian Electricity Association. However, we elected to keep the process less detailed at the outset so as to not

[23] *IEEE Standard Terms for Reporting and Analyzing Outage Occurrences and Outages States of Electrical Transmission Facilities*

overcomplicate start-up. Also, we are currently more detailed in our data requirements than Schedule 7 in EIA's Form 411.

In the TADS framework, we will have Element outage frequency rates and failure rates. With regard to Protection System failures, we have not defined the Protection System as a TADS Element to be tracked. (The term "Protection System" is defined in TADS and is the same definition used in NERC's Reliability Standards.) Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems – requires each Regional Reliability Organization to "establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations." We realize that potential metrics could be developed if TADS were linked to the data derived from these standards, and while that is not a practical goal at this point, it could be part of a TADS expansion at a future date.

EIA's suggestions for expanding TADS can be considered, along with other TADS improvements, after NERC develops a process for soliciting and evaluating TADS improvements (see Section 5.2 of the preliminary Phase II report).

- NEMA provided comments related to additional future data for Transformers:

> "[We] would find additional detail on equipment characteristics beneficial. For a given outage, a unique element identifier is already reported. NEMA would find it particularly useful to also record the date of manufacture or in-service date of that transmission element, either through the same form or through a separate table linking the transmission element to its nameplate characteristics. For transformers, other nameplate information would also include power rating, voltage rating, BIL rating, insulation class, cooling class, temperature class, impedance, frequency and presence of a load tap changer.

NEMA's suggestions will be considered, along with other TADS improvements, after NERC develops a process for soliciting and evaluating TADS improvements (see Section 5.2 of the preliminary Phase II report).

- Nebraska Public Power District (NPPD) asked that we develop a "forced outage rate" metric that reflects both Automatic Outages plus Operational Outages. The task force has had difficulty with the term "forced outage rate" because it may be defined differently by different TOs, and we will not add this as a general metric. For example, the Canadian Electricity Association defines a "forced outage" in TADS terms as Automatic Outages plus Non-Automatic Operational Outages with an Emergency Cause Code. However, NPPD's suggestion has merit. We will specify that webTADS modifications for Phase II permit the user to develop metrics that combine data from Phase I (Automatic Outages) along with data from Phase II (Non-Automatic Outages which are Operational Outages). That way each TO can calculate its own "forced outage rate" metric.

3.7 Maintaining Five-Years of Supporting Data

Although 77% of the responding TOs agreed to the proposed five-year period for the retention of supporting TADS data, 19% (12 TOs) felt it was unreasonable. Specific negative comments are shown below, and responses to all of them are provided in a coordinated discussion at the end of this section.

IESO said:

> "While the IESO supports the need to ensure validity and quality of data, we believe 5 years is excessive and support a shorter data retention period of 3 years. The IESO is unaware of any existing process to validate EIA data and question the need here."

Entergy said the five-year retention period was reasonable, but said:

> "….guidelines on acceptable documentation would be helpful in assuring no efforts are put into going overboard in this effort."

WECC and six WECC TOs said:[24]

> "This is an unreasonable request. Past years' data is often incompatible with current data because of potential circuit definitions changes in each system and potential metric definition changes."

PacifiCorp expressed a similar concern:

> "It is not reasonable to maintain TADS-quality data for an extended period of time. The further away the event occurred, the less likely it can be readily replayed and understood. As a result, derivative metrics for a given time period may make sense, however the raw data documenting any planned outage activities does not make sense due to the ever-changing nature of the delivery system, including generation locations, transmission corridors and markets."

CenterPoint Energy stated:

> "The data review process requirements for the Regional Entities and the webTADS error checking features implemented in Phase I should provide the necessary level of data validation. Data errors should be able to be corrected within the annual NERC reporting process. The webTADS database should serve as the historical repository for analytical purposes and replace the need for the proposed 5-year record retention and review process for the transmission owners."

ITC Holdings said:

> "It appears that the choice of the 5 year retention period was arbitrary. Again the maintenance and archiving of such data will require additional resources for a yet to be determined benefit."

[24] Arizona Public Service, Idaho Power, SMUD, Salt River Project, WAPA-Desert Southwest Region, and WAPA-Rocky Mountain Region

Tallahassee stated:

> "1. If NERC can't determine that my data is accurate rapidly, they are collecting too much information or not collecting the correct data to start with.
> 2. Why are you placing the burden of record retention on the [reporting] entity? We have enough other NERC "stuff" to track and retain.
> 3. The "historical supporting information" is not clear. This can be anything and everything! And I am sure what I think I need to retain would not be the same that you think I need to retain, especially if this turns into a Standard."

EIA recommended:

> "… extending the period of [keeping] historic period [data] beyond 5 years. For example, the age of many types of installed equipment or components on the bulk power systems could easily be described as mature. Failure rates attributed to age and their associated failure trends are best observed over a wider base of years."

Our response to all of the comments above follows.

As described in Section 5.1 of the preliminary Phase II report, we intend to conduct a data review with each reporting TO with the objective of ensuring that the TO has a reasonable and consistent process for both interpreting the outages and recording the data. To answer IESO's comment, there is no existing NERC process to validate EIA data that NERC voluntarily collects and submits to EIA, and EIA has rightfully questioned the validity of such data. To answer CenterPoint Energy's comment and Tallahassee's first comment, we do have data error checking capability built into webTADS, but that is no guarantee that the data has been collected reasonably and that the instructions were interpreted properly.[25] Regarding Tallahassee's second comment, the entity that submits TADS data is responsible for its accuracy and completeness.

While NERC's review of a TO's collection process and supporting data will cover the most recent reporting period, NERC cannot practically review 192 reporting entities[26] in a single year. The five-year retention period allows NERC to accomplish a review of every TO, and if a TO which NERC visits in the fifth year has a systematic reporting error, past data entries can be corrected. While the five-year policy may have appeared arbitrary to ITC Holdings, we realize that we did not explain it fully and will do so in the final Phase II report.

We agree with the WECC, the six WECC TOs, and PacifiCorp that past data may be incompatible with current data and that circuits may have changed. Changes will occur every year. Nevertheless, to ensure that the data has been consistently collected by all TOs, TOs need to maintain historical supporting information. Tallahassee correctly notes that we have not defined what comprises "historical supporting information," and Entergy also asked for "guidelines." What a TO should keep for documentation is best determined by the TO, but a simple guideline is this: any information that a TO relied upon to complete a webTADS data entry should be kept for five years.

[25] For an analogy, a tax return filed to the Internal Revenue Service undergoes many logic and consistency checks before it is accepted. While that does mean the data entered is consistent with the logic checks, it does not mean that the tax payer has properly interpreted the tax regulations.

[26] 192 reporting entities equals the NERC IDs and the current pseudo NERC IDs that are reporting Phase I data.

Regarding EIA's comment, TADS data itself will *not* have a time limit for data retention. What we are limiting is the time that a TO needs to retain its historical supporting data for its entries into TADS.

3.8 Non-U.S. Reporting Requirements

In response to Manitoba Hydro's comments asking whether Phase II TADS data is required from Canadian utilities, we clarify that Phase II TADS data *is* required of non-U.S. Transmission Owners that are also NERC members. See Section A.3 of the April 30, 2008 request for comments which states **"**Non-U.S. Transmission Owners [on the NERC Compliance Registry] who are also NERC members are required to comply with NERC's *Rules of Procedure*, and because Phase II TADS data are being requested in accordance with Section 1600, [these] non-U.S. Transmission Owners too must provide Phase II TADS data."

In response to comments from Manitoba Hydro, Hydro One, and the IESO, we clarify whether any TADS data submitted by a Canadian entity will be reported to EIA or FERC:

- In the Phase I Report dated September 26, 2007, p. 6 states the following in footnote 6: "TADS data from Canadian Transmission Owners will not be reported to EIA unless approved by those Canadian TOs."
- In the preliminary Phase II report, p. 10 states the following in footnote 13: "Each ERO governmental authority would be able to access confidential information for Transmission Owners that it regulates, e.g., FERC would only be able to access TADS data for U.S. Transmission Owners, and an appropriate Canadian provincial regulatory body would only be able to access TADS data for its provincial Transmission Owners."

3.9 The Manual

While most TOs were complimentary of the Manual, 16 TOs reported ambiguities in the Manual. Exelon and ITC Holdings (representing a combined five TOs) asked for better justification for Phase II in the Manual, but this is not the purpose of the Manual.

From other TOs, we received several good Manual "content" questions:

- Hydro One and TVA asked that we provide an example of human error as described in the "Other Planned Outage" Planned Outage Cause Code. NPPD asked for an example of "Other Planned Outage." We respond to both questions with one example: If the outage instructions are mislabeled and, as a result, the wrong circuit is opened for a Planned Outage, the mistake will eventually be realized. If the situation is rectified by opening the intended circuit and restoring the unintended circuit, the unintended circuit would have an "Other Planned Outage" Planned Outage Cause Code because the outage was due to human error. The intended circuit would have a "Maintenance and Construction" Planned Outage Cause Code.
- NPPD and Entergy had similar questions regarding two parties being involved in an outage request. We provide NPPD's question directly:

  > "If a Third Party (for example: the department of roads or a house mover) requests an outage and the TO uses that outage opportunity to do maintenance to the line, does it still classify as a Third Party Outage or does it now become a Maintenance Outage? Are there any situations where a

planned outage starts out as a Third Party outage, but then becomes a maintenance or operational or "other" type of outage?"

Only one Cause Code is reported for each Non-Automatic Outage. For Non-Automatic Outages, the Cause Code that contributes to the longest duration should be reported similar to the definition for Sustained Cause Code. See the Manual, Appendix 7, p. 13, item E.1.

Returning to the previous example, suppose that the outage for the road department is expected to last four hours, and maintenance is scheduled for this interval. However, in the process of performing maintenance, additional work is discovered that is unexpected, and the outage is extended to seven hours to accommodate this additional work. Since maintenance contributed to the longest outage duration, the outage is classified as a "Maintenance and Construction" Planned Outage Cause Code since this code represented all seven of the outage hours, while "Third Party Request" only accounted for four hours. We will add language and examples in the Manual that clarify this situation.

- Reliability*First* Corporation asked that we expand two Operational Outage Cause Codes: H.2 (System Voltage Limit Mitigation) and H.3 (System Operating Limit Mitigation, excluding System Voltage Limit Mitigation) into the four separate codes using the System Operating Limit causes listed in H.3 (see the Manual, Appendix 7, pp. 16-17):
  - Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
  - Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
  - Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
  - System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

  We purposefully combined the first three System Operating Limits causes into one cause code (H.3) since the research needed to determine the exact underlying limit cause may be extensive. On the contrary, the opening of an Element to maintain system voltages is readily known and assigned its own separate cause code.

- Reliability*First* Corporation asked that the Planned Outage Cause Code for "Maintenance and Construction" have two additional cause codes added: One for "Maintenance" and a second of "Construction" where each would describe an activity that is 100% maintenance *or* construction, with the "Maintenance and Construction" describing activities that are combined. We considered this alternative and rejected it for the reasons described in the last paragraph of Section 2.1.1 of the preliminary Phase II report.

- TVA noted that in Appendix 7, p. 19, the definition of Voltage Classes includes 400-499 kV and 500-599 kV, while for AC Circuits only 400-599 kV is used. That is correct as explained in Section 1.2.1, p. 2, of the Manual. TVA also pointed out several typographical errors, which we will correct.

- Northeast Utilities said "under Phase I, the changes seemed to occur continuously without any notification of changes." We announced all the Manual changes; however, due to the coincidence of the Phase II comments with a Phase I update, we announced the Phase I update in the April 30, 2008 request for comments. See the first bullet on the first page of the request for comments. We regret any confusion and will not use this practice in the future.

- San Diego Gas & Electric said that "a good system to clarify and ask questions should be in place." We have such a system as described in Section 1.8, p. 7, of the Manual.
- National Grid asks "that future document change control be more formalized and that for any future Phase I (and Phase II if approved) TADS changes that NERC limits the frequency of updates, if any, to a quarterly basis." National Grid's suggestion will be considered, along with other TADS improvements, after NERC develops a process for soliciting and evaluating TADS improvements (see Section 5.2 of the preliminary Phase II report).
- National Grid also notes that OATI's webTADS has the capability of allowing outage start times to be entered in local time rather than Coordinated Universal Time, and asked that the TF revisit its decision to require UTC entries. We will modify webTADS in the future to allow data to be entered in local time *if* it is entered via the graphical user interface (GUI). However, it will be converted to UTC and stored in webTADS in UTC. Bulk-loaded data entry must still be in UTC. We will clarify this in a future update of the Manual.
- Hydro One said "it is not clear why the collection of terminal station names is necessary. It should be sufficient to collect the number of station terminals associated with each circuit for the calculation of the metrics. This would add value to the metrics."

  We require that each AC Circuit outage provide Substation Names because this provides others, such a Regional Entities and NERC who review TADS data, a physical location of the circuit. When we are trying to determine whether an Event has propagated between more than one TO, the Substation Names, along with the Outage Start Times, provide a basis for initiating a check with the appropriate TOs. Thus, we will have the number of terminals associated with each outaged circuit.

  What we do *not* collect is an inventory by Voltage Class of the number of circuits with two terminals or three terminals. Neither do we have an inventory of the total number of substations by Voltage Class. We agree that such data would have probable metric value, and it was debated in early 2007 when the TF was formulating its Phase I data requirements. However, it was not adopted. It will be considered, along with other TADS improvements, after NERC develops a process for soliciting and evaluating TADS improvements (see Section 5.2 of the preliminary Phase II report).
- PG&E said that instead of requiring TADS "It would be more beneficial for NERC to simply define "best practices" for outage data collection and establish timetables for transmission owners to adopt those best practices." That suggestion would not meet the minimum goals set forth in the TADSTF scope, which included standardizing the data collection process. See Appendix 1 of the Phase I Report dated September 26, 2007.

Appendix 4. TADS Task Force Members

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Personnel Certification Governance Committee

Board Action Required
None

System Operator Certification Program
Since 1998, NERC has maintained a System Operator Certification Program that establishes minimum standards of competency for system operators. The Personnel Certification Governance Committee (PCGC) is responsible for maintaining the integrity and independence of the certification process and credential.

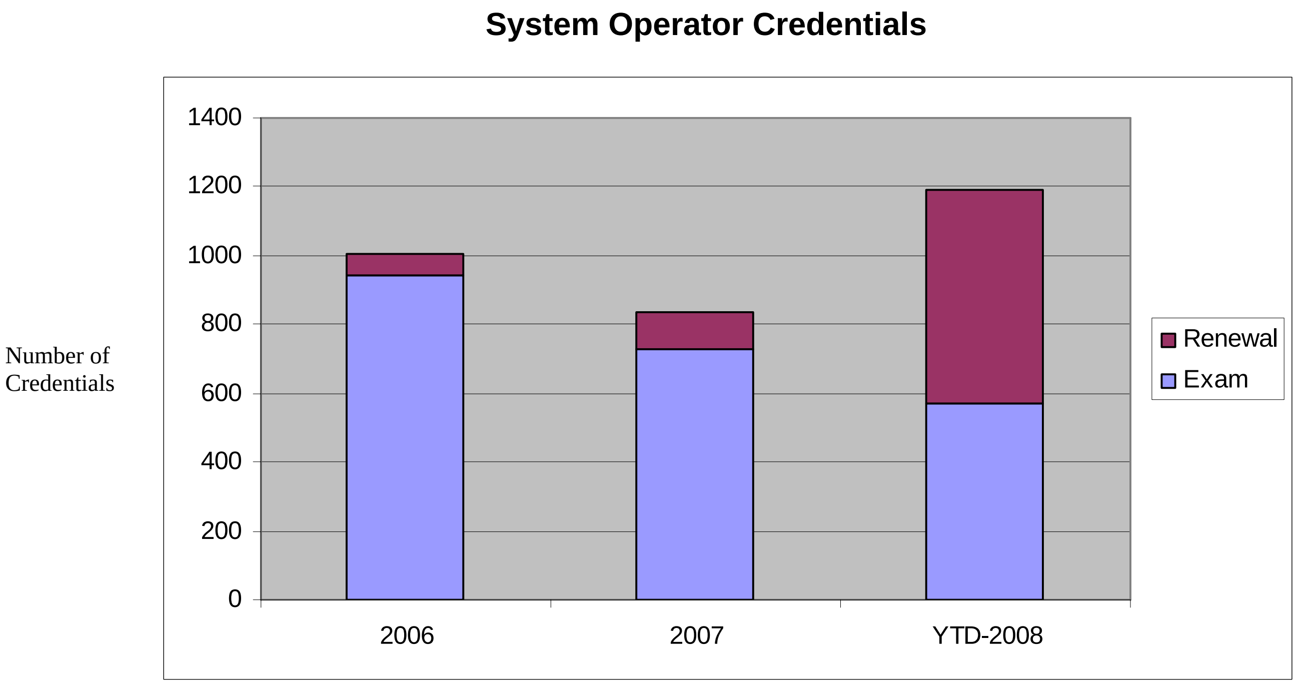
A system operator is awarded certification upon passing an examination that is based on a job analysis of their area of responsibility. The exam focuses on the knowledge and application of the NERC reliability standards and basic principles of interconnected bulk power system operation. A certification credential is maintained by earning continuing education (CE) hours through approved learning activities.

Certification and Continuing Education Database
This database tracks certified system operators from their initial application, through certification examinations, to subsequent submissions of CE hours to maintain their credential. It provides a platform through which CE providers can manage the individual learning activities they offer. The seventh change order to upgrade functionality and reporting capabilities was completed in September 2008.

System Operator Certification Examinations
The new exams were published on schedule on July 7, 2008. Exams were not available in June to facilitate the changeover to the new exams. The French-Canadian translation of the Reliability Operator exam is completed and will be published in October 2008.

The PCGC has begun the process of creating the survey instrument that will be used in the 2009 system operator job analysis. It takes about two years to complete the process from job analysis, through development of exam content outlines, to the final new exams. The results of 2009 analysis will form the basis for new exams due in 2011.

In the first three quarters of 2008, 1,191 system operator certifications were issued. The new database was only partially operational for the same period last year so comparison is not meaningful. Since expanding the certification program to include CE hours, a total of 789 credentials have been maintained (renewed) with 621 of those in the first three quarters of 2008.



As the dark area of the chart indicates, the use of CE hours to maintain a credential continues to increase since its introduction in October 2006. We are 24 months into a 36-month transition to maintaining a credential solely with CE hours. During the first three quarters of 2008, about 52 percent of the certificates were issued using this process. This represents a significant increase over the 13 percent usage in 2007. We expect the percentage of those maintaining their credential to continue to increase through the end of the transition period, October 1, 2009. There will always be a certain percentage of new system operators certifying by exam.

Advanced Certification

The PCGC is currently researching the feasibility of offering a voluntary advanced system operator certification. This certification would ideally require a demonstration of advanced knowledge, skills, and abilities and include job experience as a factor. The decision will be affected by the available population, interest in attaining the new credential, costs for developing and administering the credential, and how the credential will be viewed by the industry and regulators. If the decision is made to move forward with the credential, the earliest it could be available would be 2011.

Improving Relay Technician Performance

NERC staff and the PCGC are researching and drafting a white paper to present options to the industry regarding improving the performance of relay technicians related to system events over the past 10 years. This effort is being closely coordinated with the work of the Protection System Performance Initiative. Options will include variations on certification and training. The white paper is expected to be presented for comment to the industry in the first quarter of 2009.

North American Electric Reliability Corporation
Statement of Activities
(Unaudited)
From 1/1/2008 through 9/30/2008

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Actual Variance from Budget	2008 Projection	2008 Budget	2008 Projection Variance from Budget
Funding						
Assessments	20,433,752	18,704,246	1,729,507	25,694,031	24,938,994	755,037
Membership Fees	601,577	175,000	426,577	785,000	175,000	610,000
Testing	779,446	722,250	57,196	963,000	963,000	-
Services & Software	266,592	191,250	75,342	335,000	255,000	80,000
Workshop Fees	112,700	-	112,700	-	-	-
Interest	113,195	150,000	(36,805)	200,000	200,000	-
Misc.	357	-	357	-	-	-
Total Funding	22,307,620	19,942,745	2,364,874	27,977,031	26,531,994	1,445,037
Expenses						
Personnel Expenses						
Salaries	9,876,345	10,330,700	(454,355)	12,738,355	13,187,575	(449,220)
Payroll Taxes	659,428	698,350	(38,922)	744,973	773,557	(28,583)
Employee Benefits	1,006,997	1,267,186	(260,189)	1,623,325	1,692,607	(69,283)
Savings & Retirement	1,143,104	938,830	204,274	1,649,992	1,261,195	388,797
Total Personnel Expenses	12,685,874	13,235,065	(549,191)	16,756,645	16,914,934	(158,290)
Meeting Expenses						
Meetings	710,216	541,333	168,883	796,003	720,500	75,503
Travel	1,465,486	1,029,525	435,961	1,626,370	1,372,700	253,670
Conference Calls	117,834	84,750	33,084	134,171	113,000	21,171
Total Meeting Expenses	2,293,536	1,655,608	637,928	2,556,544	2,206,200	350,344
Operating Expenses						
Rent & Improvements	516,124	510,000	6,124	680,000	680,000	-
Contracts	2,013,148	1,970,145	43,003	2,816,860	2,626,860	190,000
Consultants	1,022,096	960,000	62,096	1,371,270	1,280,000	91,270
Office Costs	749,891	558,750	191,142	813,168	745,000	68,168
Professional Services	794,626	1,075,000	(280,374)	1,370,000	1,420,000	(50,000)
Computer Purchase & Maint.	210,403	450,000	(239,597)	742,075	600,000	142,075
Furniture & Equipment	3,098	41,250	(38,152)	55,000	55,000	-
Miscellaneous	4,741	3,000	1,741	4,000	4,000	-
Total Operating Expenses	5,314,127	5,568,144	(254,018)	7,852,373	7,410,860	441,513
Other Non-Operating Expenses	-	-	-	755,037	-	755,037
Total Expenses	20,293,537	20,458,818	(165,281)	27,920,599	26,531,994	1,388,605
Net Change in Assets	2,014,084	(516,073)	2,530,156	56,431	(0)	56,433
FTE's	94.5	101.5	(7)	100.5	101.5	(1)

North American Electric Reliability Corp
2008 Statement of Activities
01/01/2008 - 09/30/2008
Reliability Standards

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance	Comments		2008 Projection	2008 Budget (Revised to reflect DAW and JAS in G&A)	Variance
Funding								
Assessments	1,994,065	1,848,605	145,460	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	7.87%	2,464,807	2,464,807	-
Membership Fees			-					-
Testing			-					-
Services & Software			-					-
Workshop Fees	63,500		63,500					-
Interest			-					-
Misc.			-					-
Total Funding	2,057,565	1,848,605	208,960		11.30%	2,464,807	2,464,807	-
Expenses								
Personnel Expenses								
Salaries	1,328,242	1,203,650	124,592	Promotional increases above budget	10.35%	1,741,045	1,546,610	194,435
Payroll Taxes	94,497	90,212	4,285		4.75%	99,437	99,760	(323)
Employee Benefits	119,425	168,301	(48,876)	Medical benefits renewal under budget; one declined coverage	-29.04%	210,773	225,333	(14,559)
Savings & Retirement	150,491	94,897	55,594	date	58.58%	232,637	127,905	104,732
Total Personnel Expenses	1,692,655	1,557,060	135,595			2,283,892	1,999,607	284,285
Meeting Expenses								
Meetings	104,156	120,000	(15,844)		-13.20%	232,050	160,000	72,050
Travel	231,698	153,900	77,798	Travel is expected to exceed budget throughout the year	50.55%	245,700	205,200	40,500
Conference Calls	-		-					-
Total Meeting Expenses	335,854	273,900	61,954			477,750	365,200	112,550
Operating Expenses								
Rent & Improvements			-					-
Contracts			-					-
Consultants	30,610	75,000	(44,390)		-59.19%	100,000	100,000	-
Office Costs	13,000	-	13,000	Cell phone and wireless broadband internet connection cards		31,500		31,500
Professional Services			-					-
Computer Purchase & Maint.			-					-
Furniture & Equipment			-					-
Miscellaneous								
Total Operating Expenses	43,610	75,000	(31,390)			131,500	100,000	31,500
Other Non-Operating Expenses								
Total Expenses	2,072,119	1,905,960	166,159		8.72%	2,893,142	2,464,807	428,335
Net Change in Assets	(14,554)	(57,355)	42,801		-74.62%	(428,335)	(0)	(428,335)
FTE's	13.0	13.0	-			14.0	13.0	1.0

North American Electric Reliability Corp
2008 Statement of Activities
01/01/2008 - 09/30/2008
Compliance

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance Over/(Under)		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	3,719,919	3,502,120	217,799	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	4,669,493	4,669,493	-
Membership Fees			-					-
Testing			-					-
Services & Software			-					-
Workshop Fees			-					-
Interest			-					-
Misc.			-					-
Total Funding	3,719,919	3,502,120	217,799			4,669,493	4,669,493	-
Expenses								
Personnel Expenses								
Salaries	2,116,467	2,390,885	(274,417)	-11.48%	Timing of FTEs added in 2008; budgeted earlier in the year	2,801,042	3,090,959	(289,917)
Payroll Taxes	152,047	179,858	(27,811)	-15.46%		181,939	202,423	(20,484)
Employee Benefits	197,636	300,099	(102,463)	-34.14%	Medical benefits renewal under budget	365,566	403,403	(37,837)
Savings & Retirement	232,655	170,414	62,241	36.52%	Increase in Discretionary 401k Contribution per change in vesting date	341,890	233,809	108,081
Total Personnel Expenses	2,698,806	3,041,255	(342,450)			3,690,437	3,930,593	(240,156)
Meeting Expenses								
Meetings	60,781	23,750	37,031	155.92%	Meeting and travel expenses projected to exceed budget.	44,625	30,000	14,625
Travel	467,721	284,175	183,546	64.59%		500,000	378,900	121,100
Conference Calls			-					-
Total Meeting Expenses	528,502	307,925	220,577			544,625	408,900	135,725
Operating Expenses								
Rent & Improvements			-					-
Contracts			-					-
Consultants	152,127	247,500	(95,373)	-38.53%	Spend for database development behind schedule.	330,000	330,000	-
Office Costs	24,360		24,360		Cell phone and wireless broadband internet connection cards	27,000		27,000
Professional Services			-					-
Computer Purchase & Maint.			-					-
Furniture & Equipment			-					-
Miscellaneous	252		252					-
Total Operating Expenses	176,740	247,500	(70,760)			357,000	330,000	27,000
Other Non-Operating Expenses								
Total Expenses	3,404,047	3,596,680	(192,633)	-5.36%		4,592,062	4,669,493	(77,431)
Net Change in Assets	315,871	(94,561)	410,432	-434.04%		77,431	(0)	77,431
FTE's	27.0	26.0	1.0		1 position authorized over budget	27.0	26.0	1.0

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
Reliability Readiness Evaluation and Improvement

(In Whole Dollars)

	2008 YTD Actual	**2008 YTD Budget**	**2008 YTD Variance Over/(Under)**		**Comments**	**2008 Projection**	**2008 Budget**	**Variance**
Funding								
Assessments	1,480,211	1,393,546	86,665	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	1,858,061	1,858,061	-
Membership Fees			-					-
Testing			-					-
Services & Software			-					-
Workshop Fees			-					-
Interest			-					-
Misc.			-					-
Total Funding	1,480,211	1,393,546	86,665			1,858,061	1,858,061	-
Expenses								
Personnel Expenses								
Salaries	761,028	1,050,127	(289,099)	-27.53%		998,753	1,340,884	(342,131)
Payroll Taxes	59,390	82,199	(22,809)	-27.75%		66,142	88,799	(22,657)
Employee Benefits	77,762	130,459	(52,696)	-40.39%		129,562	173,945	(44,383)
Savings & Retirement	85,172	72,700	12,473	17.16%	vesting date	130,923	96,933	33,990
Total Personnel Expenses	983,353	1,335,484	(352,131)		2 unfilled positions; 1.5 transferred to other departments	1,325,380	1,700,561	(375,181)
Meeting Expenses								
Meetings	1,021		1,021			19,203		19,203
Travel	124,581	118,125	6,456	5.47%	Staff participated in several ORS and OC meetings during the first half to discuss the reform of the program. Due to the phase out of the program, expect to end the year at budgeted levels.	157,500	157,500	-
Conference Calls			-					-
Total Meeting Expenses	125,602	118,125	7,477			176,703	157,500	19,203
Operating Expenses								
Rent & Improvements			-					-
Contracts			-					-
Consultants	191,903		191,903		Consultants used in place of FTE's	125,000		125,000
Office Costs	8,118		8,118		Cell phone and wireless broadband internet connection cards	9,600		9,600
Professional Services			-					-
Computer Purchase & Maint.			-			25,000		25,000
Furniture & Equipment			-					-
Miscellaneous			-					-
Total Operating Expenses	200,021	-	200,021			159,600	-	159,600
Other Non-Operating Expenses								
Total Expenses	1,308,976	1,453,609	(144,633)	-9.95%		1,661,683	1,858,061	(196,377)
Net Change in Assets	171,235	(60,063)	231,298	-385.09%		196,378	0	196,377
FTE's	6.5	12.0	(5.5)		2 open, 3.5 transfers to another department	8.5	12.0	(3.5)

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
Reliability Assessment and Performance Analysis

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	2,175,979	2,048,577	127,402	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	2,731,436	2,731,436	-
Membership Fees			-					-
Testing			-					-
Services & Software	190,737	112,500	78,237	69.54%		225,000	150,000	75,000
Workshop Fees	40,800		40,800					-
Interest			-					-
Misc.			-					-
Total Funding	2,407,516	2,161,077	246,439			2,956,436	2,881,436	75,000
Expenses								
Personnel Expenses								
Salaries	1,240,628	1,250,222	(9,595)	-0.77%	3.5 open positions offset by $37k payments to part-time GADS	1,583,006	1,597,025	(14,019)
Payroll Taxes	76,492	78,934	(2,442)	-3.09%		86,547	87,313	(766)
Employee Benefits	144,437	160,654	(16,217)	-10.09%	Medical benefits renewal under budget	210,721	212,587	(1,866)
Savings & Retirement	159,268	152,502	6,766	4.44%	Increase in Discretionary 401k Contribution per change in vesting date	214,230	203,611	10,619
Total Personnel Expenses	1,620,825	1,642,312	(21,487)			2,094,504	2,100,536	(6,032)
Meeting Expenses								
Meetings	208,730	69,333	139,397	201.05%	Cost of OC/PC meetings budgeted in SAIS	165,274	92,500	72,774
Travel	244,676	152,550	92,126	60.39%	Travel in all departments expected to exceed budget based upon 2007 acutal results	237,500	203,400	34,100
Conference Calls			-			5,000		5,000
Total Meeting Expenses	453,405	221,883	231,522			407,774	295,900	111,874
Operating Expenses								
Rent & Improvements			-					-
Contracts	147,319	307,500	(160,181)	-52.09%	Credit for ($23k) from AEP for 2007 exp re-billed to RFC; ($55k) underspend against the TADS budget; ($86k) for analysis software budgeted here but charged to Computer Purchase & Maint.; ($6k) underspend for GADS programming; $10k overspend on assessment studies	295,000	410,000	(115,000)
Consultants	223,747	56,250	167,497	297.77%	$110.2 for Mgr of TADS filled with Consultant instead of FTE; $57.3k overspend for event analysis	201,270	75,000	126,270
Office Costs	25,034		25,034			43,177		43,177
Professional Services			-					-
Computer Purchase & Maint.	49,075		49,075		PSEC Software License budgeted in Contracts	117,075		117,075
Furniture & Equipment			-					-
Miscellaneous								
Total Operating Expenses	445,175	363,750	81,425			656,522	485,000	171,522
Other Non-Operating Expenses								
Total Expenses	2,519,405	2,227,945	291,460	13.08%		3,158,800	2,881,436	277,364
Net Change in Assets	(111,889)	(66,868)	(45,021)	67.33%		(202,364)	0	(202,364)
FTE's	8.5	11.0	(2.5)		2 open positions; 1 position filled with contractor; .5 shared with another dept; 1 transferred in	11.0	11.0	-

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
Training and Education

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	348,368	327,971	20,397	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	437,295	437,295	-
Membership Fees			-					-
Testing	779,446	722,250	57,196	7.92%		963,000	963,000	-
Services & Software			-					-
Workshop Fees								
Interest			-					-
Misc.			-					-
Total Funding	1,127,814	1,050,221	77,593			1,400,295	1,400,295	-
	-							
Expenses								
Personnel Expenses								
Salaries	513,515	559,987	(46,472)	-8.30%	1 FTE transferred to another department; 1 resigned	695,499	714,461	(18,962)
Payroll Taxes	39,806	40,429	(623)	-1.54%		42,440	43,554	(1,114)
Employee Benefits	43,910	59,187	(15,277)	-25.81%	Medical benefits renewal less than anticipated	76,555	78,916	(2,361)
Savings & Retirement	76,486	67,173	9,313	13.86%	Increase in Discretionary 401k Contribution per change in vesting date	94,175	89,564	4,611
Total Personnel Expenses	673,716	726,775	(53,060)			908,669	926,495	(17,826)
Meeting Expenses		-						
Meetings	23,718	40,500	(16,782)	-41.44%		54,000	54,000	-
Travel	33,771	41,850	(8,079)	-19.30%		66,400	55,800	10,600
Conference Calls			-			7,500		7,500
Total Meeting Expenses	57,489	82,350	(24,861)			127,900	109,800	18,100
Operating Expenses								
Rent & Improvements			-					-
Contracts	221,098	198,000	23,098	11.67%	Overspend with MCG on database development	264,000	264,000	-
Consultants	39,990	75,000	(35,010)	-46.68%		100,000	100,000	-
Office Costs	4,065		4,065			12,500		12,500
Professional Services			-					-
Computer Purchase & Maint.			-					-
Furniture & Equipment	-		-					-
Miscellaneous	102		102					
Total Operating Expenses	265,254	273,000	(7,746)			376,500	364,000	12,500
Other Non-Operating Expenses								
Total Expenses	996,459	1,082,125	(85,667)	-7.92%		1,413,069	1,400,295	12,774
Net Change in Assets	131,355	(31,904)	163,260	-511.72%		(12,774)	0	(12,774)
FTE's	4.0	6.0	(2.0)		1 FTE transferred to another department; 1 resigned	5.5	6.0	(0.5)

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
Situation Awareness and Infrastructure Security

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	2,501,029	2,354,596	146,434	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	3,139,461	3,139,461	-
Membership Fees			-					-
Testing			-					-
Services & Software	75,855	78,750	(2,895)	-3.68%		110,000	105,000	5,000
Workshop Fees	8,400		8,400					-
Interest			-					-
Misc.			-					-
Total Funding	2,585,284	2,433,346	151,939			3,249,461	3,244,461	5,000
Expenses								
Personnel Expenses								
Salaries	636,653	541,574	95,079	17.56%	1 transferred in from another department & 1 2009 FTE hired Sep08	756,251	693,952	62,298
Payroll Taxes	45,881	37,326	8,555	22.92%		43,624	40,029	3,594
Employee Benefits	62,497	34,399	28,098	81.68%	$23.5k relocation not budgeted	49,983	45,866	4,117
Savings & Retirement	66,659	59,614	7,045	11.82%	Increase in Discretionary 401k Contribution per change in vesting date	108,631	79,654	28,977
Total Personnel Expenses	811,691	672,913	138,778			958,488	859,501	98,987
Meeting Expenses								
Meetings	103,999	76,500	27,499	35.95%		80,000	102,000	(22,000)
Travel	107,399	60,075	47,324	78.77%		135,000	80,100	54,900
Conference Calls			-					-
Total Meeting Expenses	211,398	136,575	74,823		spend	215,000	182,100	32,900
Operating Expenses								
Rent & Improvements			-					-
Contracts	1,644,732	1,464,645	180,087	12.30%	Net cost to NERC for frame relay has increased due to added features.	2,149,860	1,952,860	197,000
Consultants	160,860	187,500	(26,640)	-14.21%	NASPI began mid-June, expect to spend full budget by year end	250,000	250,000	-
Office Costs	25,447		25,447			5,340		5,340
Professional Services			-					-
Computer Purchase & Maint.			-					-
Furniture & Equipment			-					-
Miscellaneous								
Total Operating Expenses	1,831,039	1,652,145	178,894			2,405,200	2,202,860	202,340
Other Non-Operating Expenses								
Total Expenses	2,854,128	2,461,633	392,495	15.94%		3,578,688	3,244,461	334,227
Net Change in Assets	(268,843)	(28,287)	(240,556)	#######		(329,227)	0	(329,227)
FTE's	7.0	5.0	2.0		1 transferred in from another department & 1 2009 FTE hired Sep08	6.0	5.0	1.0

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
Committees and Member Forums

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	568,236	534,966	33,270	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	713,288	713,288	(1)
Membership Fees	601,577	175,000	426,577	243.76%	Forum Membership Fees	785,000	175,000	610,000
Testing			-					-
Services & Software			-			-	-	-
Workshop Fees								
Interest			-					-
Misc.			-					-
Total Funding	1,169,813	709,966	459,847			1,498,288	888,288	610,000
Expenses								
Personnel Expenses								
Salaries	308,974	344,143	(35,168)	-10.22%	1 transferred to another department and 1 unbudgeted hire	408,437	435,171	(26,734)
Payroll Taxes	17,636	18,393	(757)	-4.12%		32,249	19,582	12,667
Employee Benefits	37,806	35,049	2,758	7.87%		46,731	46,731	(0)
Savings & Retirement	35,579	29,552	6,027	20.39%	date	48,432	39,403	9,029
Total Personnel Expenses	399,996	427,137	(27,141)			535,849	540,888	(5,039)
Meeting Expenses								
Meetings	7,728	105,000	(97,272)	-92.64%	Budget included OC and PC meetings; actuals charged to RAPA	30,000	140,000	(110,000)
Travel	16,795	24,300	(7,505)	-30.89%		17,768	32,400	(14,632)
Conference Calls			-					-
Total Meeting Expenses	24,523	129,300	(104,777)			47,768	172,400	(124,632)
Operating Expenses								
Rent & Improvements			-					-
Contracts			-			204,219	-	204,219
Consultants		131,250	(131,250)	-100.00%		-	175,000	(175,000)
Office Costs	5,651		5,651			5,400		5,400
Professional Services			-					-
Computer Purchase & Maint.			-					-
Furniture & Equipment			-					-
Miscellaneous	154,194		154,194		Overhead allocation per Agreement			
Total Operating Expenses	159,844	131,250	28,594			209,619	175,000	34,619
Other Non-Operating Expenses								
Total Expenses	584,363	687,687	(103,324)	-15.02%		793,236	888,288	(95,052)
Net Change in Assets	585,450	22,279	563,170	2527.77%		705,052	0	705,051
FTE's	2.0	2.0	-			2.0	2.0	-

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
General and Administrative

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget (Revised to reflect DAW and JAS in G&A)	Variance
Funding								
Assessments	3,451,978	2,745,452	706,526	25.73%	Assessments within the WECC region are collected annually. All other assessments collected quarterly. Also, $566k is for the working capital reserve	4,415,640	3,660,603	755,037
Membership Fees			-					-
Testing			-					-
Services & Software			-					-
Workshop Fees								
Interest	113,195	150,000	(36,805)	-24.54%		200,000	200,000	-
Misc.	357		357					-
Total Funding	3,565,531	2,895,452	670,079			4,615,640	3,860,603	755,037
Expenses								
Personnel Expenses								
Salaries	1,081,067	1,041,148	39,919	3.83%		1,357,782	1,287,787	69,995
Payroll Taxes	47,126	41,366	5,760	13.92%		48,547	46,201	2,346
Employee Benefits	121,298	62,118	59,180	95.27%		100,452	82,825	17,627
Savings & Retirement	122,700	80,169	42,531	53.05%		177,712	106,892	70,820
Total Personnel Expenses	1,372,191	1,224,801	147,390			1,684,493	1,523,705	160,788
Meeting Expenses								
Meetings	21,823	103,250	(81,427)	-78.86%		164,000	139,000	25,000
Travel	153,054	116,925	36,129	30.90%		163,695	155,900	7,795
Conference Calls	117,834	84,750	33,084	39.04%		121,671	113,000	8,671
Total Meeting Expenses	292,712	304,925	(12,213)			449,366	407,900	41,466
Operating Expenses								
Rent & Improvements	516,124	510,000	6,124	1.20%		680,000	680,000	-
Contracts			-			(204,219)		(204,219)
Consultants			-					-
Office Costs	374,626	352,500	22,127	6.28%	Internet expense budgeted in IT	452,551	470,000	(17,449)
Professional Services	497,712	540,000	(42,288)	-7.83%		720,000	720,000	-
Computer Purchase & Maint.			-					-
Furniture & Equipment	3,098	41,250	(38,152)	-92.49%		55,000	55,000	-
Miscellaneous	(149,807)	3,000	(152,807)		Overhead allocation to TOOF (see Member Forums) per Agreemen	4,000	4,000	-
Total Operating Expenses	1,241,754	1,446,750	(204,996)			1,707,332	1,929,000	(221,668)
Other Non-Operating Expenses						755,037		755,037
Total Expenses	2,906,657	2,976,476	(69,819)	-2.35%		4,596,228	3,860,605	735,623
Net Change in Assets	658,874	(81,023)	739,897	-913.19%		19,412	(2)	19,414

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
Legal and Regulatory

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	1,275,651	1,200,962	74,689	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	1,601,283	1,601,283	-
Membership Fees			-					-
Testing			-					-
Services & Software			-					-
Workshop Fees								
Interest			-					-
Misc.			-					-
Total Funding	1,275,651	1,200,962	74,689			1,601,283	1,601,283	-
Expenses								
Personnel Expenses								
Salaries	527,718	674,771	(147,053)	-21.79%	Hired consultant as Canadian Affairs Representative budgeted as FTE; transferred (1) to G&A	651,012	848,599	(197,587)
Payroll Taxes	23,175	35,524	(12,349)	-34.76%		30,183	39,344	(9,161)
Employee Benefits	46,493	63,106	(16,613)	-26.33%		64,550	84,142	(19,591)
Savings & Retirement	57,677	56,174	1,503	2.68%	Increase in Discretionary 401k Contribution per change in vesting date	94,397	74,898	19,499
Total Personnel Expenses	655,063	829,575	(174,512)			840,143	1,046,983	(206,840)
Meeting Expenses								
Meetings		3,000	(3,000)	-100.00%		3,000	3,000	-
Travel	38,578	38,475	103	0.27%		37,715	51,300	(13,585)
Conference Calls			-					-
Total Meeting Expenses	38,578	41,475	(2,897)			40,715	54,300	(13,585)
Operating Expenses								
Rent & Improvements			-					-
Contracts			-			108,000		108,000
Consultants	61,265	-	61,265	100.00%	Canadian Affairs Representative budgeted as FTE			-
Office Costs	4,187	-	4,187	100.00%		8,050		8,050
Professional Services	260,064	375,000	(114,936)	-30.65%	Timing-expect to spend full budget	500,000	500,000	-
Computer Purchase & Maint.			-					-
Furniture & Equipment			-					-
Miscellaneous								
Total Operating Expenses	325,516	375,000	(49,484)			616,050	500,000	116,050
Other Non-Operating Expenses								
Total Expenses	1,019,157	1,246,050	(226,893)	-18.21%		1,496,908	1,601,283	(104,375)
Net Change in Assets	256,494	(45,087)	301,581	-668.88%		104,375	0	104,375

North American Electric Reliability Corp
2008 Statement of
Activities
01/01/08 - 09/30/08
Information Technology

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	1,835,254	1,727,801	107,453	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	2,303,735	2,303,735	-
Membership Fees			-					-
Testing			-					-
Services & Software			-					-
Workshop Fees								
Interest			-					-
Misc.			-					-
Total Funding	1,835,254	1,727,801	107,453			2,303,735	2,303,735	-
Expenses								
Personnel Expenses								
Salaries	708,235	659,665	48,570	7.36%	1 year severance for termed employee; promotional increase and bonuses higher than planned	885,800	843,695	42,105
Payroll Taxes	52,778	50,561	2,217	4.39%		60,306	57,439	2,867
Employee Benefits	73,355	98,271	(24,917)	-25.35%	Group health renewal less than budget and (1) open position	138,031	131,470	6,561
Savings & Retirement	88,569	86,029	2,540	2.95%	Increase in Discretionary 401k Contribution per change in vesting date	113,238	115,531	(2,293)
Total Personnel Expenses	922,937	894,527	28,411			1,197,375	1,148,135	49,240
Meeting Expenses								
Meetings	(4,283)		(4,283)					-
Travel	24,948	22,950	1,998	8.70%		38,000	30,600	7,400
Conference Calls			-					-
Total Meeting Expenses	20,665	22,950	(2,285)		Travel is expected to exceed budget in all areas based upon 2007 actual spend	38,000	30,600	7,400
Operating Expenses								
Rent & Improvements			-					-
Contracts			-					-
Consultants	161,594	187,500	(25,906)	-13.82%		250,000	250,000	-
Office Costs	261,205	206,250	54,955	26.64%	($58.8k) Internet expense for general office moved to GA; $93.8k over spend for computer supplies and maintenance. The over spend for computer supplies is offset by the under spend for capitalized computer purchases below.	209,700	275,000	(65,300)
Professional Services			-					-
Computer Purchase & Maint.	161,328	450,000	(288,672)	-64.15%	See notation above under Office Costs	600,000	600,000	-
Furniture & Equipment			-					-
Miscellaneous								
Total Operating Expenses	584,127	843,750	(259,623)			1,059,700	1,125,000	(65,300)
Other Non-Operating Expenses								
Total Expenses	1,527,729	1,761,227	(233,498)	-13.26%		2,295,075	2,303,735	(8,660)
Net Change in Assets	307,525	(33,425)	340,951	#######		8,660	0	8,660

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
Human Resources

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	377,575	355,469	22,107	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	473,958	473,958	-
Membership Fees			-					-
Testing			-					-
Services & Software			-					-
Workshop Fees								
Interest			-					-
Misc.			-					-
Total Funding	377,575	355,469	22,107			473,958	473,958	-
Expenses								
Personnel Expenses								
Salaries	238,524	223,673	14,851	6.64%	budget	332,314	289,910	42,404
Payroll Taxes	18,888	16,202	2,686	16.58%		20,776	18,125	2,651
Employee Benefits	31,193	93,327	(62,135)	-66.58%	Education reimbursements-$3,000 utilized in Q1 and charged to Readiness	142,638	124,437	18,201
Savings & Retirement	30,225	24,365	5,860	24.05%	spread	41,516	32,486	9,030
Total Personnel Expenses	318,829	357,567	(38,738)			537,244	464,958	72,286
Meeting Expenses								
Meetings	191		191					-
Travel	9,339	6,750	2,589	38.36%		10,784	9,000	1,784
Conference Calls			-					-
Total Meeting Expenses	9,530	6,750	2,780			10,784	9,000	1,784
Operating Expenses								
Rent & Improvements			-					-
Contracts			-					-
Consultants	-		-			15,000		15,000
Office Costs	3,393		3,393			6,350		6,350
Professional Services			-					-
Computer Purchase & Maint.			-					-
Furniture & Equipment			-					-
Miscellaneous								
Total Operating Expenses	3,393	-	3,393			21,350	-	21,350
Other Non-Operating Expenses								
Total Expenses	331,752	364,317	(32,564)	-8.94%		569,378	473,958	95,420
Net Change in Assets	45,823	(8,848)	54,671	-617.89%		(95,420)	0	(95,420)

North American Electric Reliability Corp
2008 Statement of Activities
01/01/08 - 09/30/08
Accounting and Finance

(In Whole Dollars)

	2008 YTD Actual	2008 YTD Budget	2008 YTD Variance		Comments	2008 Projection	2008 Budget	Variance
Funding								
Assessments	705,486	664,181	41,306	6.22%	Assessments within the WECC region are collected annually. All other assessments collected quarterly.	885,574	885,574	-
Membership Fees			-					-
Testing			-					-
Services & Software			-					-
Workshop Fees								
Interest			-					-
Misc.			-					-
Total Funding	705,486	664,181	41,306			885,574	885,574	-
Expenses								
Personnel Expenses								
Salaries	415,295	390,857	24,438	6.25%	Additional FTE for 2 months	527,415	498,523	28,891
Payroll Taxes	31,712	27,346	4,366	15.96%		32,784	30,988	1,796
Employee Benefits	51,183	62,215	(11,032)	-17.73%	Medical benefits renewal less than anticipated	87,762	82,954	4,808
Savings & Retirement	37,623	45,241	(7,618)	-16.84%		52,211	60,509	(8,298)
Total Personnel Expenses	535,813	525,660	10,153			700,171	672,974	27,198
Meeting Expenses								
Meetings	182,353		182,353		OLK expenses to be allocated to departments	3,850		3,850
Travel	12,925	9,450	3,475	36.78%		16,308	12,600	3,708
Conference Calls			-					-
Total Meeting Expenses	195,279	9,450	185,829			20,158	12,600	7,558
Operating Expenses								
Rent & Improvements			-					-
Contracts			-					-
Consultants			-					-
Office Costs	805		805			2,000		2,000
Professional Services	36,849	160,000	(123,151)	-76.97%	Funds budgeted for SAS70 audit not yet needed; $50K budgeted for IA function will not be used	150,000	200,000	(50,000)
Computer Purchase & Maint.			-					-
Furniture & Equipment			-					-
Miscellaneous								
Total Operating Expenses	37,654	160,000	(122,346)			152,000	200,000	(48,000)
Other Non-Operating Expenses								
Total Expenses	768,745	695,110	73,635	10.59%		872,329	885,574	(13,244)
Net Change in Assets	(63,259)	(30,930)	(32,329)	104.53%		13,245	0	13,244