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Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: 2006 Biennial Transmission Assessment Workshop 1
Docket No. E-00000D-05-0040

Dear Sir/Madame:

Enclosed is Arizona Public Service Company's ("APS"') response to questions posted following the June 6, 2006 BTA Workshop 1 meeting.

If you or your staff have any questions regarding the responses please contact Bob Smith at 602-250-1144.

Sincerely,

Brian Brumfield
Supervisor
Regulation, Pricing and Administration

BB/vld

Attachments

Cc: Docket Control (Original, 13 copies)
Jerry Smith, ACC
Robert Kondziolka, SRP
Ed Beck, TEP
Bruce Evans, SWTC
Ron Moulton. WAPA

General questions to the group

Q1. What WECC reports or committee activities may better inform our review of the BTA filings?

The Western Electricity Coordinating Council (WECC) Planning and Coordination Committee (PCC) and Technical Studies Subcommittee (TSS) meeting minutes will contain updates and annual progress reports for major extra high voltage (EHV) projects that could impact Arizona.

The PCC meeting minutes are located at:

http://www.wecc.biz/index.php?module=pagesetter&func=viewpub&tid=4&pid=5

The TSS meeting minutes are located at:

http://www.wecc.biz/index.php?module=pagesetter&func=viewpub&tid=4&pid=6

Q2. What other reports would you suggest we review concerning:

- *Demonstrating AZ regional planning activities:*

  The following reports and websites provide additional information regarding regional planning activities that include Arizona issues. Included are website links to the reports.

  - Southwest Area Transmission (SWAT) reports:

    http://www.azpower.org/swat/

  - Reports of the Southwest Transmission Expansion Plan (STEP) sub-regional planning group. Those reports are located on the California Independent Scheduling Coordinator (CALISO) website:

    http://www.caiso.com/docs/2002/11/04/2002110417450022131.html

  - The APS OASIS also contains a number of reports relating to current and proposed projects:

    http://www.oatioasis.com/azps/index.html

- *Support work and projects discussed at the workshop:*

  The reports and websites referenced above also address issues relating to the work and projects discussed in the presentations provided at the last workshop.

- *Developments related to:*

- *EPAct 2005*

  The Department of Energy (DOE) has established a website to provide updates on its activities pursuant to the Energy Policy Act of 2005 (EPAct 2005).

  The general DOE website is located at:

  http://www.oe.energy.gov/

  The DOE's EPAct 2005 website is located at:

  http://www.oe.energy.gov/energy_policy/epa_sec368.htm

  The Western Congestion Assessment Task Force (WCATF), APS , and other Arizona and Southwest utilities and planning groups have provided comments on DOE's EPAct 2005 Sections 368 and 1221 activities. Those comments are available on the DOE websites. For convenience, APS is attaching copies of its own comments.

  The Federal Energy Regulatory Commission (FERC) recently issued a Notice of Proposed Rulemaking (NOPR) for the backstop siting authority given to it by EPAct 2005. The FERC has created an EPAct 2005 website, which can be found at:

  http://www.ferc.gov/legal/maj-ord-reg/fed-sta/ene-pol-act.asp

  A link to the siting NOPR can be found on the above website.

  NERC/WECC standards – FERC Staff prepared comments on the North American Electric Reliability Council proposed Version 0 reliability standards. Those comments can be found on the FERC EPAct 2005 website referenced above. For your convenience, a copy is provided with this filing.

  The WECC standards development webpage can be found at the following webpage:

  http://www.wecc.biz/index.php?module=pnForum&func=viewforum&forum=1

  A link to the NERC section of the WECC can be found on the WECC's home page at:

  http://www.wecc.biz/

- *WECC committee structure and functions*

  Information regarding the WECC committee structure and functions is provided on the WECC website at:

http://www.wecc.biz/

The WECC committee web page is located at:

http://www.wecc.biz/wrap.php?file=wrap/committee.html

Q3. Are there any issues before the WECC Transmission Expansion Planning Policy committee that may have an impact on the filings?

The Transmission Expansion Planning Policy Committee (TEPPC) currently is in the formation stage and has had no impact as of yet. The TEPPC has established a web page, which is located at:

http://www.wecc.biz/index.php?module=pagesetter&func=viewpub&tid=5&pid=49

Q4. To what extent do your planning activities align with the proposed changes to FERC's Order 888?

In its OATT Reform Notice of Proposed Rulemaking (Docket No. RM05-25), the FERC is proposing to include transmission planning processes in Open Access Transmission Tariffs (OATTs). The proposal requires each transmission provider's planning process meet the eight planning principles, which include coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, and congestion studies. APS believes that the planning processes it participates in today meet most, if not all, of these principles.

The FERC recognized in the Notice of Proposed Rulemaking that voluntary regional planning efforts were encouraging, and specifically identified the sub-regional planning processes in the WECC as being proactive:

> We are encouraged that since the adoption of open access in Order No. 888, a number of voluntary coordinated and regional planning efforts have been developed throughout the country.... In addition, each of the subregions in WECC has a coordinated transmission planning process that, in varying degrees, is open to market participants and, in some instances, has resulted in significant new transmission being built on a joint ownership basis.

Docket RM05-25 at ¶ 211.

Q5. In regard to EPAct 2005—What measures have been implemented in the transmission planning area, if any, related to the FERC/NERC/WECC mandatory reliability requirements?

There are several rulemakings underway at FERC relating to the formation of an Electric Reliability Organization (ERO) and the mandatory reliability requirements that will be promulgated by the ERO. It is likely that many of the "Version 0" requirements that were adopted by NERC last year will be adopted as the reliability requirements of the ERO. The Version 0 requirements include some requirements relating to transmission planning, and APS has been complying with these requirements since they were issued by NERC. We are also following and participating in the various ERO rulemakings and will participate in the standards development processes of the ERO.

Questions for each participant

Q6. Are any of the projects included in your 10-year plans being proposed solely for their economic benefits (as opposed to reliability benefits)?

All of the transmission projects included in the filed APS' 10-year plan are driven by reliability need. Many of these projects also have an economic benefit to APS customers by providing access to less expensive resources. There presently are no projects in APS' filed plan that are proposed solely for their economic benefit to APS customers. Although not shown in APS' 10-year plan, APS is a participant in the planned East of River (EOR) 9300 project, a project to upgrade existing facilities from the Westwing and Navajo Substations into Southern Nevada. While the project will provide increased transmission capability in both directions between Arizona and Southern Nevada and thus will contribute to long term regional reliability APS and the other participants could operate their individual systems within applicable reliability criteria even if this project were not built. Therefore, this project could be considered an economic project that would allow access to less expensive resources and provide an economic benefit to APS customers.

Q7. How do the proposed transmission plans provide for delivery of new generation sources to Arizona customers:

- *In-state generation—general locations considered?*

  The proposed transmission plans provide for delivery of new generation at the Palo Verde Hub area. The plans also provide for additional import capability into the Phoenix area load center, which will allow additional resources to be imported on other transmission paths:

- *Generation imports—directions considered (from where?)*

  Although it is not in APS' filed 10-year plan, APS is currently performing a feasibility study for the TransWest Express Project, a new interstate transmission line that would provide access to up to 3,000 megawatts of clean, low-cost coal and renewable wind energy in Wyoming for Arizona and other utilities in California, Colorado, New Mexico, Nevada, and Utah. In addition to providing access to energy resources for rapid growth areas in the Southwest, TransWest Express will benefit all western states by providing improved reliability of the western grid. APS is working with other interested stakeholders and has completed the transmission and permitting portions of its feasibility analysis. The result of this analysis, along with internal economic analysis that APS has completed, indicate that the project alternatives being studied are feasible and would provide significant economic and other benefits.

APS also is involved, through SWAT, in study work to develop plans for additional transmission that would increase the capability to import power from New Mexico.

Q8. How do you identify RMR areas? How do you define the RMR area boundaries?

RMR areas are identified based on operational experience and/or power flow studies. RMR boundaries are determined based on sensitivity analyses. The import limit area or load pocket is defined as that load which, when increased, would increase the severity of the limiting contingency. A description of this methodology is provided on pages 14-17 in the 2004-2013 RMR report, which has been provided to the Arizona Corporation Commission.

Q9. Based on the CATS HV and other studies does it appear that Pinal County has the potential to become an RMR area in the future?

Based upon studies performed to date in the various sub-regional planning groups, the potential for Pinal County to become an RMR area in the future is low and highly dependant upon what projects are assumed for any study. Of the projects that were used as assumptions in the CATS-HV study that are actively being pursued at this time, most of them are transmission projects that would bring more import/export capability to the area. Those projects therefore likely would maintain the ability to import power into the region ahead of the load for the region.

Q10. How have WAPA's transmission improvements been incorporated into the plans presented at the workshop?

The power flow cases that APS used for 10-year planning studies created by jointly developing three WECC Heavy Summer cases (2009, 2012, and 2015) and the 2005 Valley operating case between SRP, APS, SWTC, TEP, and WAPA. Each utility reviewed the case, including updating their loads and existing facilities, and providing their most current plans. Therefore, at the time of APS' study, WAPA and the other utilities had reviewed and updated the four base cases.

Q11. Where can we find the 10-year load forecast information used in your studies?

The combined APS/SRP Phoenix area load and APS Yuma area load can be found in the 2006-2015 RMR study on page 36 for the 2008 and 2015 study years. The overall APS system load for each of the 10 years studied is not reported in the 10-year plan, but can be included in all future filings.

Q12. Discuss any difficulty you may have in providing the following information as part of future BTAs:

- *A table reporting the assumed load for each year studied; and*

  Reporting the forecasted/assumed load for each year studied would not be difficult and APS is willing to provide such information as part of future BTAs.

- *Reporting the specific contingency (or base case), limiting element, the nature of the limit, and the extent that criteria are violated that justifies each transmission addition.*

  APS currently provides this information in the Technical Results section of the 10-year plan filing. APS also provides a pre-project power flow map and a post-project power flow map of the overloaded element(s).

Federal Energy Regulatory Commission
Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards

May 11, 2006

RM06-16-000

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I. EXECUTIVE SUMMARY

The Charge from Congress

With the passage of the Energy Policy Act of 2005, the United States Congress entrusted the Federal Energy Regulatory Commission (Commission) with the authority to approve and enforce rules to assure reliability of the Nation's Bulk-Power System. Section 1211 of the Energy Policy Act of 2005[1] (EPAct 2005) creates section 215 of the Federal Power Act (FPA), which requires the Commission to issue rules for the certification of an Electric Reliability Organization (ERO). The ERO will be responsible for developing and enforcing mandatory Reliability Standards, subject to Commission approval, that provide for an adequate level of reliability of the Bulk-Power System. The law mandates that all users, owners, and operators of the Bulk-Power System in the United States will be subject to the Commission-approved Reliability Standards, in contrast to the current system of voluntary compliance with industry-developed reliability standards managed by the North American Electric Reliability Council (NERC).[2]

In discharging its responsibility to review, approve and enforce mandatory Reliability Standards, the Commission is authorized to approve only those proposed standards that meet the criteria detailed by Congress:

> The Commission may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[3]

In considering whether a Reliability Standard meets the statutory criteria, the Commission must give "due weight" to "technical expertise" of the ERO or any Regional Entity organized on an interconnection-wide basis.

This preliminary staff assessment is the first step in an open and inclusive process that will allow interested persons to submit comments on whether the proposed mandatory

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[1] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005) (to be codified at 16 U.S.C. § 824o).

[2] This assessment capitalizes the words "Reliability Standard" only when referring to mandatory Reliability Standards approved by the Commission. This assessment capitalizes the words "Requirements," "Measures," "Compliance" and "Levels of Non-Compliance" when referring to those named sections in the NERC standards.

[3] Section 215(d)(2) of the FPA, to be codified at 16 U.S.C. § 824o(d)(2) (2000).

Reliability Standards found in NERC's petition meet the statutory criteria and will allow the Commission to develop an adequate record on which to make the required statutory findings. Staff began the analysis by evaluating the current voluntary reliability standards listed on NERC's website prior to its filed petition. Staff anticipated that the proposed mandatory Reliability Standards would have the same, or nearly the same, content as the current voluntary reliability standards but kept current on any revised or new standards that were developed. On April 4, NERC filed 102 reliability standards with the Commission requesting that they be approved and subsequently made mandatory. This assessment reviews these standards.

As explained further below, staff has identified numerous deficiencies in the standards filed by NERC for approval and is seeking comment on them. In many instances, NERC has identified the same concerns in its April 4, 2006 standards petition and has proposed a workplan to address them. We commend NERC for taking this proactive role. In other instances, staff has identified potential deficiencies for which there is no proposed work plan in NERC's petition. We seek comment on these potential deficiencies, whether the proposed Reliability Standards containing such potential deficiencies meet the statutory criteria and, if not, the process by which the standards should be revised, including giving priority to those that are of the greatest importance to Bulk-Power System reliability.

Initial Commission Activity – Order No. 672

The Commission began implementation of section 215 of the FPA with Order No. 672, issued on February 3, 2006.[4] Among other things, Order No. 672 established criteria that an entity must satisfy to qualify to be the ERO and procedures under which the ERO may propose new or modified Reliability Standards for Commission review. In its final rule, the Commission provided guidance on the factors it would consider when determining whether proposed Reliability Standards meet the statutory criteria.[5]

For example, the guidance states that a proposed Reliability Standard must be designed to achieve a specified reliability goal and be clear and unambiguous regarding what is required and who is required to comply. In order to be approved, a proposed Reliability Standard does not have to reflect the "best practice," but it similarly cannot be a compromise based on the "lowest common denominator," if such a Standard would not

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[4] *Rules Concerning Certification of the Electric Reliability Organization: and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 71 FR 8,662 (Feb. 17, 2006), FERC Stats. & Regs. Regulations Preambles ¶ 31, 204 (2006), *order on reh'g,* Order No. 672-A, 114 FERC ¶ 61,328 (2006).

[5] *See* Order No. 672 at P 320-36.

efficiently and effectively achieve its reliability goal. A full discussion of the factors listed in Order No. 672 can be found in the Background/Purpose Chapter of this assessment. Ultimately, the Commission has the regulatory responsibility to approve Reliability Standards that protect Bulk-Power System reliability .

Staff Activity

In anticipation of NERC submitting an ERO certification application with a concurrent filing for Commission approval of NERC's existing voluntary standards as mandatory and enforceable Reliability Standards pursuant to section 215 of the FPA, Chairman Kelliher, in the fall of 2005, directed the Commission's Division of Reliability to initiate a thorough technical review of the existing voluntary standards.

This preliminary assessment by Commission staff is the product of that months-long review. It is limited to a technical review as it makes no final determinations about whether the proposed Reliability Standards meet the Commission's criteria. Its purpose is to solicit industry comment on the potential deficiencies in the current standards and the appropriate process and timeline for addressing them. Although staff has conducted a comprehensive internal review of the standards, we believe it is important that the industry and affected stakeholders have the opportunity to review our preliminary assessment before the Commission takes any actions with regard to the proposed standards. Such an open and inclusive process will ensure that all interested persons have an opportunity for comment on the proposed standards and that the Commission has an adequate record upon which to discharge its statutory responsibilities.

NERC's Application and Proposed Reliability Standards

The current NERC voluntary standards are the product of industry's dedication and persistence over decades to develop, enforce, and improve reliability standards. Based on information provided by NERC and industry, it appears that much of the existing Bulk-Power System is planned and operated in ways that may actually surpass the criteria specified in the existing standards.[6] However, at a minimum, it appears that all users, owners, and operators generally comply with the current voluntary standards and that good utility practice is the norm. During the transition period to mandatory Reliability

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[6] Examples include practices cited in NERC's "Examples of Excellence" found in its Readiness Audits, filings for jurisdictional utilities in Part 4 of FERC Form No. 715, Transmission Planning Reliability Criteria. Regional Reliability Organizations also specify requirements that exceed NERC Standards such as WECC's Minimum Operating Requirement Criteria and the NPCC Document A-02 - Basic Criteria for Design and Operation of Interconnected Power Systems.

Standards, jurisdictional public utilities should continue to follow the existing standards as part of good utility practice under their existing open access transmission tariffs.

On April 4, 2006, NERC filed with the Commission its application for certification as the ERO.[7] NERC simultaneously submitted a petition for Commission approval of 102 proposed Reliability Standards.[8] The proposed Standards are identical to the current voluntary standards analyzed in this assessment.

In undertaking a preliminary assessment of these standards, staff has identified a number of deficiencies. In making this assessment, however, staff concludes that NERC's voluntary standards program represents a solid foundation on which to maintain and improve the reliability of the Nation's Bulk-Power System. Staff favors NERC's own interpretation as to the state of its standards:

> Although the Version 0 Reliability Standards signified an important milestone in NERC's history, it was only a beginning point. An appropriate analogy is that the Version 0 standards represent the establishment of a base camp for standards at 7,000 feet. The revised and new standards recently approved by the board are the first few hundred feet of the climb above the base camp. Much more challenging work remains in the climb to achieve technically excellent reliability standards for the North American bulk-power system.[9]

Staff views the long-term Standards development process as one of continuous improvement and is pleased to note that NERC, in evaluating its own proposed standards, discussed a number of areas for improvement on some of the topics discussed in this assessment. The Commission will be looking for public input on these and other areas for improvement at a number of different points during the Standards approval process, particularly at the upcoming technical conference. For this assessment and beyond, of particular interest to staff are comments concerning the effectiveness of NERC's proposed Reliability Standards, transitional issues, and any process changes that might be necessary to achieve "technical excellence."

Preliminary Staff Assessment

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[7] Application for Certification as the Electric Reliability Organization, Docket No. RR06-1-000 (April 4, 2006).

[8] Petition for Approval of Reliability Standards, Docket No. RM06-16-000 (April 4, 2006) (petition).

[9] *Id.* at 69.

This preliminary staff assessment represents the first step in an open and inclusive process whereby the Commission will implement EPAct 2005's goal of establishing and enforcing mandatory reliability standards that meet the statutory criteria. The primary goals of the staff assessment are to:

- Provide a basis for soliciting input regarding which of the proposed Reliability Standards should be approved, approved on an interim or conditional basis, or remanded to the ERO.[10]

- Establish a platform from which to identify and prioritize potential problems with the proposed Standards that must be addressed as the industry transitions into the mandatory Reliability Standards paradigm.

- Provide a comprehensive and objective assessment of NERC's current 102 reliability standards in view of the Blackout Report recommendations,[11] system blackouts and other disturbances, the Commission's *Utility Vegetation Management and Bulk Electric Reliability Report* to Congress, and the guidance provided by the Commission in Order No. 672.

The preliminary staff assessment has identified a number of potential deficiencies in the proposed standards. We note, however, that many of these deficiencies, particularly those related to measures and fill-in-the-blank standards, have also been identified by NERC in its standards petition and NERC has proposed a workplan for addressing them. Our review has identified many additional deficiencies as well. We summarize the major areas of concern below, including those concerns identified by NERC in its petition:

- <u>Blackout Report Recommendations</u>: Although the Blackout Report identified many of the primary causes of the August 2003 blackout and other major blackouts in the United States, many of its recommendations are not yet addressed in the reliability standards.[12] NERC has activities in place to address the

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[10] It is staff's view that the authority to approve standards on a conditional basis or to make some form of interim approval is within the scope of the Commission's authority to remand or approve standards under FPA section 215. This conditional approval authority will enable some assurance of reliability while NERC has an opportunity to improve the standard in question.

[11] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, at 107 (Blackout Report). The Task Force investigated the causes of the 2003 blackout and recommended actions to be taken to prevent future widespread outages.

[12] The Blackout Report recommended changes that impact the following topical categories of standards, each examined in its respective chapter of this report: Communications, Emergency

(continued)

recommendations, but they have not yet resulted in full implementation in the reliability standards.

- Ambiguity: Elements of numerous standards appear to be subject to multiple interpretations, especially with regard to the specificity of the standards' requirements, measurability, and degrees of compliance.[13] This ambiguity also extends to the differing definitions for the Bulk-Power System and the Bulk Electric System.[14]

- Technical Adequacy: The requirements specified in some standards may not be sufficient to ensure an adequate level of reliability. While Order No. 672 notes that "best practice" may be an inappropriately high standard, it also warns that a "lowest common denominator" approach will not be acceptable if it is not sufficient to ensure system reliability.[15] NERC's petition acknowledges that considerable effort is needed to bring the standards to the anticipated level of excellence and commits to working toward that goal.

- Measures and Compliance: These two components are absent in many of the standards, which could lead to inconsistent interpretation and enforcement of the standards.[16] NERC's petition identifies 21 standards in this category and states that a project is underway to file the Measures and Compliance components by November 2006.

Operations, Facility Design, Interchange Scheduling, Interconnection Reliability Operations, Modeling, Personnel Performance, Protection and Control, Transmission Operations, and Voltage and Reactive.

[13] Representative examples are contained in the chapters pertaining to Interconnected Reliability Operations and Coordination, Transmission Operations, and Transmission Planning. NERC's Compliance Element Drafting Standards Team has independently identified 55 requirements in 14 standards that need more definition or are vague. The drafting team, which is charged with providing compliance elements for the 21 standards identified by NERC that do not have compliance elements, posted their first draft at: ftp://www.nerc.com/pub/sys/all_updl/standards/sar/Missing_Compl_Measures_Set1_Clean_18Apr06.pdf.

[14] The Bulk-Power System is the term used to describe jurisdiction of the ERO in EPAct 2005 and Order No. 672 whereas the Bulk Electric System is the term used by NERC to describe the jurisdiction of its standards. A more complete discussion of this issue can be found in section G of the Common Issues chapter of this assessment.

[15] Order No. 672 at P 328-29 (representative examples are contained in the chapters pertaining to Personnel Performance Training and Qualification; Modeling, Data, and Analysis; and Transmission Planning).

[16] *See* Appendix C which lists standards that lack either Measures or Levels of Non-Compliance.

- Undue Negative Impact on Competition: The primary purpose of this assessment was to provide a technical reliability analysis of the proposed standards, rather than to identify those that could have an undue negative impact on competition.[17] However, in certain instances staff identifies standards that could raise such concerns, such as the standards that govern the calculation of Available Transfer Capability (ATC). The Commission is considering the issues associated with ATC calculation in greater detail in Docket Nos. RM05-17-000 and RM05-25-000.

- Fill-in-the-Blank Standards: "Fill-in-the-Blank Standards" refer to those standards for which Version 0 does not contain a specific requirement that is enforceable against users, owners and operators of the grid, but rather provides only broad direction to the Regional Reliability Organizations (RROs) to adopt a particular standard. These standards raise concerns in two respects (i) they are not enforceable against users, owners and operators of the grid, but rather only provide broad direction to RROs, and (ii) the more specific implementing standards adopted by the RROs have not undergone an approval process under section 215 and hence cannot themselves be enforced by the Commission or ERO. Beyond the near-term enforceability problems associated with these types of standards, there are concerns that the "blanks" be populated in ways that do not generate unnecessary regional differences.[18] NERC's petition acknowledges there are issues with fill-in-the-blank standards and proposes both short-term and long-term solutions.

- Applicability: FPA section 215 requires that "all users, owners, and operators" comply with mandatory reliability standards approved by the Commission. The current standards do not define or list the "users, owners, and operators" that are required to follow the standard.[19] The applicability of each standard needs to be clear.

This assessment identifies staff's preliminary observations and concerns regarding NERC's current standards. It begins by reviewing the issues common to a number of the

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[17] Representative examples are contained in the chapters pertaining to Modeling, Data and Analysis and to Resource and Demand Balancing.

[18] Representative examples are contained in the chapters pertaining to Modeling, Data and Analysis, Resource and Demand Balancing, and Protection and Control.

[19] Representative examples are contained in the chapters pertaining to Data and Analysis, Transmission Planning, and Protection and Control.

standards. Following the discussion of these common issues, this assessment includes chapters devoted to each category of standards as defined in NERC's petition. Each chapter examines the primary issues within the category in question as well as a specific analysis of each standard in that category.

Next Steps and Challenges Ahead

Staff recognizes the goal of the Commission to establish sound and enforceable Reliability Standards as soon as practicable, consistent with the statutory requirements of FPA section 215. Staff understands the limits of Commission authority, in particular, that it cannot directly modify the proposed Reliability Standards in the course of its approval review process. FPA section 215 authorizes the Commission to remand or approve the Reliability Standards. It is our view, however, that included within the Commission's approval authority is the discretion to conditionally approve standards or to make some form of interim approval in order to provide some assurances of reliability while NERC has an opportunity to improve the standard in question. Staff also acknowledges that FPA section 215 requires the Commission to give "due weight" to the technical expertise of the ERO with respect to the content of a proposed Reliability Standard and therefore presents this document in the context of a technical review for public comment. In order to determine whether the proposed standards meet the statutory criteria, while giving due weight to the technical expertise of the ERO, we are soliciting comments on our preliminary assessment. Once the Commission has reviewed these comments, it will issue a Notice of Proposed Rulemaking that proposes to approve those standards that meet the statutory criteria and, as necessary, to remand or conditionally accept any standards that do not meet the statutory criteria.

This preliminary assessment is the first step in an open process to establish technically sound and legally enforceable Reliability Standards that meet the statutory criteria in FPA section 215. The Commission initiated a rulemaking establishing the process for approving or remanding proposed Reliability Standards in part to assure the greatest possible degree of openness in the process. Undertaking the task by rulemaking allows us to have discussions with Canadian regulators, Mexican authorities, and State regulators; interested Federal Agencies; NERC; regional organizations; the industry; customers; and other stakeholders.

The next step will be the technical conference, which will be announced at a future date. Following the conference, the Commission will propose a rule in which it will (1) approve those proposed Reliability Standards that meet statutory criteria, (2) approve for an interim period or conditionally approve proposed Reliability Standards, and (3) remand proposed Reliability Standards that are determined not to meet the statutory criteria. Opportunity for public comment will be available at each interval.

The Commission recognizes the difficulty of making the transition from a regime of voluntary standards to North American Reliability Standards that are both technically sound and legally enforceable. It also recognizes the practical limits on the ability of NERC, Regional Reliability Organizations (RROs), and industry to modify any reliability standards quickly. For that reason, our immediate focus is on those Reliability Standards that are most important to Bulk-Power System reliability. In particular, this will mean focusing on the proposed Reliability Standards that can be shown to affect the safety and security of the Nation through its Bulk-Power System. For example, staff is concerned that certain recommendations of the Blackout Report have not yet been fully implemented and we therefore seek comments on whether these recommendations should be given the highest priority by the Commission and the industry. To the extent proposed Reliability Standards may fall short of Commission criteria, our focus will be on identifying the flaws in such standards so that they can be improved to the point where they meet the criteria as soon as feasible and be approved by the Commission.

Interested persons are invited to utilize this staff assessment of the current standards to inform their input to the Commission in its consideration of NERC's petition for approval of proposed Reliability Standards. Staff agrees with NERC that a tremendous amount of work lies ahead "to achieve technically excellent reliability standards" for the Bulk-Power System in North America. In particular, staff is soliciting input from interested persons to help the Commission identify which standards deserve immediate industry attention and solutions, as well as suggestions for an appropriate plan for addressing the intermediate and longer term improvements which are necessary. With the shift to mandatory Reliability Standards, the Commission expects appropriate and timely improvements in the development and implementation of Reliability Standards necessary to protect the Bulk-Power System and has provided appropriate programs by which to evaluate this objective.[20]

[20] For example, the ERO must affirmatively demonstrate to the Commission at the end of the first three-year period, and every five years thereafter, that it can develop and enforce reliability standards and that it is improving the quality of its activities and those of the Regional Entities to which the ERO has delegated such activities.

II. BACKGROUND/PURPOSE

A. Background

Before NERC was formed, reliability of the interconnected electric grid was managed by the planning and operating criteria, guidelines, and policies of individual electric utilities and groups of interconnected utilities. Operating policies were then expanded to larger areas and international scale under the auspices of the North American Power Systems Interconnected Committee, which was formed in 1962, and ultimately merged with NERC in 1980.

Shortly after the Northeast Blackout of 1965, Regional Reliability Organizations (RRO)[21] started to form in the Northeastern United States and Ontario, Canada. In 1968, the electric utility industry established NERC to coordinate the RROs' activities and to ensure reliability of the electricity supply in North America. By the mid-1990s, NERC began to develop planning standards through a committee system of industry representatives.[22] During this transition, utilities continued to use and maintain their planning policies in conjunction with the development of standards by NERC.[23]

In June 2002, the NERC Board of Trustees approved adoption of an open stakeholder process for the development of reliability standards and NERC was accredited by the American National Standards Institute (ANSI) in March of 2003. NERC planned to revise or develop each standard individually using the ANSI process. However, with the occurrence of the August 2003 blackout, NERC accelerated its efforts and developed as a group the Version 0 standards as a translation of many of NERC's existing operating policies, planning standards and compliance templates.[24]

NERC's reliability standards currently consist of 102 separate standards and a glossary, which are organized by topic in 14 categories. Together the standards cover a wide range

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[21] A Regional Reliability Organization (RRO) is a regional entity of NERC that ensures that a defined area of the Bulk Electric System is reliable, adequate, and secure. There are currently eight NERC regions with eight corresponding RROs.

[22] North American Electric Reliability Council, NERC Planning Standards (1997).

[23] Jurisdictional utilities file their Transmission Planning Reliability Criteria (*i.e.*, their planning policies), with the Commission as Part 4 of FERC Form No. 715. Staff notes that most utilities' Criteria are more robust than NERC's planning standards.

[24] *See* Blackout Report at 161 (NERC's change in plans was based on Recommendation Number 25, which suggested accelerating the adoption of enforceable standards).

of reliability issues – from transmission planning and operations to communications and emergency preparedness.[25]

Each NERC standard follows a consistent format:

A. Introduction

1. Title: a phrase that describes the topic of the standard.

2. Number: A unique identification number that starts with three letters to identify the group followed by a dash and then three digit number followed by a dash and the version number *e.g.*, PRC-014-0.

3. Purpose: One or more sentences that explicitly states the outcome to be achieved by the adoption of the standard.

4. Applicability:

4.1. Which entity, as defined by the Functional Model, must comply with the standard, such as Transmission Owner.

5. Effective Date: The date that the standard becomes effective in terms of audits and compliance.

B. Requirements

R1. A listing of explicitly stated technical, performance and preparedness requirements and who is responsible for achieving them.

C. Measures

M1. A listing of the factors used to assess performance and outcomes in order to determine compliance, and who is responsible for achieving the measures.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility: Who is responsible for assessing performance or outcomes?

1.2. Compliance Monitoring Period and Reset Timeframe: What is the timeframe for each compliance monitoring period before it is reset for the next period?

1.3. Data Retention: How long does the compliance documentation need to remain on file?

1.4. Additional Compliance Information: Any other information.

2. Levels of Non-Compliance: Usually four levels of non-compliance are identified with level 1 being used for the least severe non-compliance and level 4 for the most severe non-

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[25] The categories are: Resource and Demand Balancing; Critical Infrastructure Protection; Communications; Emergency Preparedness and Operations; Facilities Design, Connections and Maintenance; Interchange Scheduling and Coordination; Modeling, Data, and Analysis; Organization Certification; Personnel Performance, Training, and Qualifications; Protection and Control; Transmission Operations; Transmission Planning; and Voltage and Reactive. The Organization Certification category does not contain any standards and was therefore not reviewed. Standards that have been adopted by NERC and those under development are available at www.nerc.com.

compliance.

E. Regional Differences: Identification of any Regional differences that have been approved by the applicable NERC Committee (including Regions that are exempt).

Version History: The chronological history of changes to the standard.

B. August 2003 Blackout

On August 14, 2003, an electrical outage in Ohio precipitated a cascading blackout across seven other states and as far north as Ontario, leaving more than 50 million people without power.[26] The August 2003 blackout was the largest blackout in the history of the United States, leaving some parts of the nation without power for up to four days and costing between $4 billion and $10 billion.[27] The 2003 blackout was the eighth major blackout experienced in North America since the 1965 Northeast Blackout.

On August 15, 2003, President George W. Bush and then-Prime Minister Jean Chrétien directed the creation of a Joint U.S.-Canada Power System Outage Task Force to investigate the causes of the blackout and ways to reduce the possibility of future outages. The U.S.-Canada Task Force convened, investigated the causes of this blackout, and recommended actions to prevent future widespread outages.

The Task Force issued a final Blackout Report in April 2004 with 46 specific recommendations to address the primary causes to help prevent or minimize the scale of future blackouts. These included a recommendation to "make reliability standards mandatory and enforceable, with penalties for noncompliance,"[28] as well as specific recommendations to change some existing reliability standards.

In addition, the Blackout Report identified eight factors that were common to some of the eight major outage occurrences from the 1965 Northeast Blackout through the 2003 Blackout, as shown below:

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[26]Blackout Report at 1.

[27] *Id.*

[28] *Id.* at 140 (the Task Force made 46 recommendations urging improvements to: enhance the situational awareness of operators; establish training and certification requirements for operators, reliability coordinators, and operator support staff; upgrade the effectiveness of internal and external communications during alerts, emergencies and other critical situations; and improve vegetation management).

> (1) conductor contact with trees; (2) overestimation of dynamic reactive output of system generators; (3) inability of system operators or coordinators to visualize events on the entire system; (4) failure to ensure that system operation was within safe limits; (5) lack of coordination on system protection; (6) ineffective communication; (7) lack of "safety nets;" and (8) inadequate training of operating personnel.[29]

The Blackout Report also listed recurring recommendations to address these common factors from these previous blackout investigations.

C. EPAct 2005 and Order No. 672

In EPAct 2005, Congress entrusted the Commission with the responsibility of reviewing and approving mandatory reliability standards that meet certain statutory criteria. EPAct 2005 sets forth this charge in a new section 215 to the Federal Power Act (FPA) by requiring the Commission to issue a rule detailing the process for certifying an entity as the ERO and for establishing and maintaining mandatory Reliability Standards. Section 215 of the FPA includes specific criteria that an entity must satisfy in order to be certified as the ERO by the Commission.[30] In addition to outlining the certification process, section 215 provides that the ERO will develop mandatory, enforceable Reliability Standards, subject to Commission approval.

To qualify as the ERO, an applicant must demonstrate, *inter alia*, that it has the ability to develop and enforce Reliability Standards that provide for "an adequate level of reliability of the bulk-power system."[31] According to the statute, the Commission may approve a proposed Reliability Standard that it determines to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[32] The Commission may also remand a proposed Reliability Standard and may call for the ERO to develop a new standard, or for the revision of an existing Reliability Standard. If approved, a Reliability Standard is mandatory for the particular users, owners and operators of the Bulk-Power System identified in the Reliability Standard. An approved Reliability Standard is enforceable by the ERO, a Regional Entity that has been delegated enforcement authority, and/or the Commission.

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[29] *Id.* at 107.

[30] Section 215(c) of the FPA.

[31] Section 215(c)(1) of the FPA.

[32] Section 215(d)(2) of the FPA.

On February 3, 2006, the Commission issued Order No. 672, which implements section 215 of the FPA. Order No. 672, among other things, sets forth procedures under which the ERO may propose a new or modified Reliability Standard for Commission review. In addition, Order No. 672 provides guidance regarding certain factors the Commission will consider when determining whether a proposed Reliability Standard satisfies the statutory standard of review.[33]

According to this guidance, a proposed Reliability Standard must provide for the reliable operation of Bulk-Power System facilities. A proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities. It must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. The possible consequences for violating a proposed Reliability Standard should be clear and understandable to those who must comply. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. While a proposed Reliability Standard does not necessarily have to reflect the optimal method for achieving its reliability goal, a proposed Standard should achieve its reliability goal effectively and efficiently. A proposed Reliability Standard must do more than simply reflect stakeholder agreement or consensus around the "lowest common denominator." It is important that the Standards developed through any consensus process be sufficient to adequately protect Bulk-Power System reliability.

A proposed Reliability Standard may take into account the size of the entity that must comply and the costs of implementation for a proposed Reliability Standard. However, the ERO should not propose standards that would achieve less than operational excellence or are otherwise inadequate to support the Bulk-Power System. A proposed Reliability Standard should be a single Standard that applies across the North American Bulk-Power System to the maximum extent this is achievable taking into account geographic variations in grid characteristics, terrain, weather, and other factors. It should also account for regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard. A proposed Reliability Standard should have no undue negative effect on competition.

The timetable for implementation of a proposed Reliability Standard will also be considered, including how a proposal balances any urgency in the need for

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[33] *See* Order No. 672 at P 320-36.

implementation against the reasonableness of the time allowed for those who must comply, along with the time needed for Canadian and Mexican authorities to act.[34] The Commission will consider whether the ERO followed its Commission-approved Reliability Standards development process. Further, should the ERO balance a particular reliability goal against other public interests, the Commission will expect an explanation for such balancing to be a part of the Standard proposal. Finally, it is worth noting that section 1241 of EPAct 2005 specifically provides that the Commission shall establish by rule transmission rate recovery mechanisms which "allow recovery of all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215 . . . ."[35]

D. Subject, Purpose and Commission Context for this Review

The Commission recognizes the significance of Congress' mandate that it oversee reliability of the Bulk-Power System. At the direction of Chairman Kelliher, in the fall of 2005, the Division of Reliability initiated this preliminary technical assessment of the current NERC voluntary reliability standards. Staff anticipates that this review will assist in developing a more complete record concerning the Petition for Approval of Reliability Standards that NERC filed on April 4, 2006. This review reflects staff's present understanding of the standards and does not reflect Commission policy. It does not make recommendations for Commission action regarding the standards, nor does it make recommendations to NERC. Rather, the review identifies issues raised by NERC's existing voluntary standards in light of the statutory mandate to develop a comprehensive plan for mandatory Reliability Standards. This review will initiate an open and inclusive process by which all interested persons can comment on the adequacy of the existing standards and the process for improving them over time.

This assessment examines NERC's standards in chapters, grouping similar standards as NERC has done. Each NERC category has a corresponding chapter in this assessment. Each chapter examines general issues within that standards group and primary issues presented by the group. It then analyzes each standard within the group.

The staff's examination of NERC's standards is comprehensive in the sense that all of NERC's current standards were evaluated. However, this assessment is not exhaustive in that the issues highlighted by staff are only those deemed most significant and do not

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[34] *Id.* at P 409.

[35] Section 219(b)(4)(A) of the FPA. *See also* Order No. 672 at P 259.

necessarily reflect every issue identified in every standard. Appendix A lists the specific standards reviewed in this assessment.

This assessment identifies staff's present observations and concerns regarding NERC's current standards. Staff also anticipates that this assessment will generate input on the standards from industry, states, government agencies and the public. As stated in the title, this is a preliminary assessment of staff; we expect the analysis to evolve and that the Commission's understanding of these issues will benefit from additional public comment in the proposed rulemaking proceeding.

III. COMMON ISSUES

This chapter discusses the issues that recur across the topical categories of the NERC standards, as determined by this staff review of NERC's Version 0 and Version 1 standards, including the accompanying Glossary of Terms Used in Reliability Standards. This overview provides context for the further assessment of a given topical group or individual standard in subsequent chapters.

A. Blackout Report Recommendations

The August 2003 blackout was of a magnitude not previously experienced in North America. In total, over 50 million citizens lost power at a loss of 4 to 10 billion dollars. In its wake, the United States and Canada, and their respective utility industries, undertook an unprecedented coordinated investigation into the causes of the blackout. The President of the United States and the Prime Minister of Canada directed that a Joint U.S.-Canada Power System Outage Task Force be established. The Task Force undertook an analysis to identify the primary cause of the blackout and to develop recommendations to prevent or minimize the scope of future blackouts.

The Blackout Report provided 46 specific recommendations to improve reliability based on the lessons learned from the August 14, 2003 blackout and seven previous major outages dating back to 1965. Thirteen of the Blackout Report recommendations address the NERC reliability standards that were in effect on a voluntary basis at the time of the Blackout Report. To implement these 13 recommendations, specific provisions in 22 standards would be required in the areas of: emergency operations; vegetation management; operating personnel training; protection systems and their coordination; operating tools and backup facilities; reactive power and voltage control; system modeling and data exchanges; communications protocols and facilities; requirements to determination of equipment ratings; synchronized data recorders; clearer criteria for operationally critical facilities; and appropriate use of Transmission Loading Relief Process.

Following issuance of the Blackout Report, NERC and the industry have been working to implement recommendations. Progress has been made and the process continues. NERC further explains the progress made to implement the Blackout Report recommendations in its standards petition.

Despite this progress, however, the reliability standards (both Version 0 and Version 1) continue to reflect several of the deficiencies identified by the Blackout Report. For example, the Blackout Report found that "deficiency in training contributed to the lack of situational awareness and failure to declare an emergency on August 14 while operator intervention was still possible (before events began to occur at a speed beyond human control)."[36] The Task Force therefore recommended that the standards contain requirements for formal training programs, including specified minimum training requirements (Recommendation Number 19). However, the reliability standards do not fully implement this recommendation. Although Personnel Performance standards PER-002 to PER-004 set forth broad objectives that a training program must satisfy, they do not specify the minimum expectations of a training program or the minimum number of hours of training (other than a requirement of five days per year for realistic simulation training) consistent with the roles, responsibilities and authorities of operating and support personnel. Therefore, the nature, objective, and criteria of operator training programs and minimum hours of training are open to interpretation. This lack of specificity allows programs to vary widely with each Transmission Operator or Balancing Authority and still comply with the standards.

There are other areas in which the reliability standards do not fully reflect the recommendations of the Blackout Report. For example, staff is concerned that, although the industry developed a vegetation management standard to implement Blackout Report Recommendation Number 16, the minimum electrical clearance portion of that standard is sufficiently low that it may not be adequate to maintain reliability or otherwise protect public safety. Staff also is concerned that, although the Blackout Report recommended the development of uniform and consistent methodologies for transmission line and equipment ratings (Recommendation Number 27), the reliability standards do not yet include such a requirement. The Blackout Report also recommended that transmission line loading relief (TLRs) not be used in situations involving an actual violation of a SOL or IROL (Recommendation Number 31), but the standards do not yet reflect this recommendation. We identify other areas as well in which the Blackout Report recommendations may not have been fully implemented in the current reliability standards.

Staff seeks comment on whether and, if so, how the reliability standards should be reformed to fully address the recommendations of the Blackout Report.

B. Ambiguities and Potential Multiple Interpretations

Various elements of numerous standards appear to be subject to multiple interpretations, especially with regard to the lack of specificity in the standards' requirements, measurability, and degrees of compliance.

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[36] Blackout Report at 157.

The Interconnection Reliability Operations and Coordination (IRO) standards are a good example of the potential for multiple interpretations and the resulting impact on the reliability of the interconnected grid. Standard IRO-005-0 states:

> If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes.[37]

One interpretation of this Requirement allows an Interconnection Reliability Operating Limit (IROL) to be exceeded during normal operation (prior to a contingency) provided that corrective actions are taken within 30 minutes. Under this interpretation, if a single critical contingency[38] occurs during this period – *i.e.*, when IROL is exceeded but prior to completion of corrective actions – the interconnection could experience instability, uncontrolled separation or perhaps cascading outages. A more conservative interpretation of this Requirement would allow IROL to be exceeded only after a single critical contingency and with the expectation that the system must be returned to a secure condition as soon as possible, but no later than 30 minutes after the contingency occurs.

This particular issue of variable interpretation in the IRO standards relating to IROL violations contributing to system instability also affects other standards such as TOP-004-0 and TOP-007-0.

C. Technical Adequacy

At times, the Requirements (*i.e.*, the technical performance and preparedness requirements for the various entities responsible for achieving them) specified in certain standards may not be sufficient to ensure an adequate level of reliability. While Order No. 672 notes that "best practice" may be an inappropriately high standard, it also warns that a "lowest common denominator" approach will be unacceptable if it is insufficient to ensure system reliability. Two examples of standards that may contain inadequate technical requirement elements follow below:

Transmission Vegetation Management

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[37] North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standard IRO-005-0 (R3).

[38] The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

The Transmission Vegetation Management standard (FAC-003-1) requires a Transmission Owner to determine and document the minimum allowable clearance between energized conductors and vegetation before the next trimming. It specifically provides that "Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*).[39] However, IEEE Standard 516-2003 is intended for use as a guide by highly-trained maintenance personnel to carry out live-line work using specialized tools under controlled environments and operating conditions, not for those conditions necessary to safely carry out vegetation management practices.[40]

The allowable clearances in the IEEE standard are significantly lower than those specified by the relevant U.S. safety codes. As such, use of IEEE clearance provision as a basis for minimum clearance prior to the next tree trimming as a Requirement in vegetation management may not be appropriate for safety and reliability reasons. For example, the IEEE Standard 516-2003 specifies a 2.45-foot clearance from a live conductor for the 120 kV voltage class,[41] whereas the ANSI Z-133 standard specifies 12-feet, 4-inches as the approach distance for the 115 kV voltage class.[42]

Staff notes that some transmission owners currently use more stringent requirements and therefore, adopting the IEEE clearance provision for use with regular vegetation maintenance practices could be viewed as a "lowest common denominator" approach, about which the Commission expressed dissatisfaction in Order No. 672. Widespread implementation of this approach could inadvertently subject the public to safety hazards and the potential for multiple tree contacts under non-controlled conditions. In addition, use of the IEEE Standard 516-2003 could create unintended consequences that cause the transmission owners who currently maintain more stringent vegetation management programs based on standards such as the ANSI Z-133 to relax their practices to meet the less-stringent minimum requirement set forth in the NERC vegetation standard, exactly

[39] North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standard FAC-003-1 (R1.2.2).

[40] Controlled environments and operating conditions include clear days without precipitation, high winds, or lightning.

[41] Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 516-2003, IEEE Guide for Maintenance Methods at 20.

[42] ANSI Z133, American National Standards Institute Standard for Tree Care Operations – Pruning, Trimming, Repairing, Maintaining and Removing Trees, and Cutting Brush – Safety Requirements.

the opposite result intended by EPAct 2005 and FPA section 215. As a result, the danger could exist that increased amounts of vegetation will become vulnerable to tree contact, the initial trigger point of the August 2003 blackout. Staff is not necessarily recommending use of the ANSI Z-133 standard as the minimum standard; however, we seek comment on whether the IEEE standard is sufficient to maintain reliability and protect public safety and, if not, what modifications to that standard should be made or whether an alternative standard is required to satisfy Order No. 672.

Transmission Planning

The Transmission Planning standards also provide an illustration of standards that may be inadequate from a technical perspective. These standards contain technical deficiencies, vague language that could be subject to multiple interpretations. For example, Standard TPL-002-0 requires a Planning Authority and Transmission Planner to demonstrate that its portion of the interconnected transmission system can meet projected customer demands and projected firm transactions while capable of withstanding the Category B contingencies.

The TPL Category B contingencies only include loss of a *single* element, defined as a generator, transmission circuit, transformer, or single DC pole with or without a fault. This definition does not cover all of the single element failures that are known to occur in actual operation. The unanticipated failure of some single elements in the Bulk-Power System can result in the loss of multiple elements. Because of the resulting impact on reliability of the loss of more elements than those defined in Category B, some Regions base their groupings according to the event, irrespective of the number of elements forced out of service.[43] For such a Region, a single event that results in the loss of multiple elements (*e.g.*, a relay failure that forces a DC bi-pole out of service or a lightning strike that simultaneously forces both circuits of a double circuit tower line out of service) are grouped alongside those events which would result in loss of single elements, such as a generator, transmission circuit or transformer, in essence providing a more stringent level of reliability.

With such variation in criteria, what is acceptable in one Region is not acceptable in another Region for reasons related to historical adoption of reliability criteria and practices rather than geography or system topology. The result could be that some Regions have differentiated and higher standards than others.

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[43] *See, e.g.*, NPCC criteria A1 Document.

D. Measures and Levels of Non-Compliance

The Measures in the standards specify the criteria that are used to determine if an entity is in compliance with the NERC standard. The Levels of Non-Compliance establish criteria for determining the severity of a violation of the standard. However, these sections are nonexistent or incomplete in many standards, either of which could contribute to varying interpretation of whether violations have occurred and the severity of the violation. Recognizing this, NERC has proposed to add Measures or Levels of Non-Compliance to 21 of the standards in November 2006. We commend NERC for undertaking this effort. This report nonetheless identifies the standards that lack Measures or Levels of Non-Compliance because these standards have been submitted for Commission approval without such specificity.

Of the current NERC standards, staff found that 26 standards do not contain any Measures, or do not contain Levels of Non-Compliance, or lack provisions in both categories.[44] Some standards have Measures but do not have Levels of Non-Compliance. For example, the Frequency and Response Bias standard (BAL-003-0) has a Measure requiring Balancing Authorities to perform Frequency Response surveys, but it does not have any Levels of Non-Compliance to identify the severity of a violation or to otherwise facilitate enforcement.

Mandatory Reliability Standards should contain Measures that address each Requirement. The Standards should also contain Levels of Non-compliance that address all of the Measures. In addition, they would be more complete and less subject to variable implementation if they included use of performance metrics, where applicable. Performance metrics provide a vehicle to gauge the effectiveness of the standards. Performance metrics can be used to assess the overall reliability of the Bulk-Power System, monitor trends and to determine whether improvements are required in the standards. A few reliability standards already do include such performance metrics, but there is potential for many more to do so.

The Levels of Non-Compliance sections are meant to facilitate enforcement and generally address the severity of violations of a standard and depend on factors such as the degree of impact on reliability and the frequency of instances of non-compliance. For example, in the recently approved standard on Transmission Vegetation Management Program, there are three Levels of Non-Compliance ranging from whether the Transmission Vegetation Management Program has all necessary documentation to meet

[44] Appendix C identifies each standard's retention of Measures or Levels of Non-Compliance.

the Requirements to the number of transmission outages due to tree contracts.[45] This element is a good example of striving to improve reliability by setting the performance metric of the number of transmission outages due to tree contacts to near zero. However, as explained above, some standards do not provide any Levels of Non-Compliance, and not all standards identify such performance metrics even when they contain Levels of Non-Compliance.

Measures and Levels of Non-Compliance are essential to the enforcement of the proposed mandatory Reliability Standards. Staff notes that if Measures and Levels of Non-Compliance are unclear in the standard, the standard may not be enforceable. Staff further notes that the NERC Compliance Penalties and Sanctions Task Force plans to address the lack of penalties and sanctions in the standards.[46]

E. Fill-in-the-Blank Standards

In the context of the mandatory Reliability Standards required by section 215 of the FPA, fill-in-the-blank standards raise two principal concerns: (i) they are not enforceable against users, owners and operators of the grid, but rather only provide broad direction to RROs; and (ii) the specific implementing standards adopted by the RROs have not undergone an approval process under section 215 and hence cannot themselves be enforced by the Commission or ERO.

In its petition, NERC identifies a total of 39 standards it refers to as "fill-in-the-blank" standards, according to any of the three sets of qualifying conditions it describes.[47] In this assessment, staff identifies 28 standards[48] as "fill-in-the-blank" standards which have the RRO's as either the only entity or one of the entities identified in the Applicability section. Staff's concern with these standards is their unclear enforceability under section 215 of the FPA for those that apply only to an RRO. This issue is more fully discussed in section (F) Applicability of NERC Standards below. We are specifically soliciting comments on the applicability of standards to an RRO in the context of NERC defined "fill-in-the-blank" standards.

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[45] *See* North American Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standard FAC-003-1.

[46] *See* NERC ERO Implementation Task Group Assignment, Compliance Penalties and Sanctions Task Force, *available at* http://www.nerc.com/~bot/cpstg.html.

[47] Petition at 87-89.

[48] Appendix B: Standards with Unclear Enforceability Under EPACT 2005.

In its petition, NERC describes a working plan to evaluate the fill-in-the-blanks standards and to modify, replace or withdraw them in an effort to allow the ERO Reliability Standards to become fully enforceable.[49] NERC states:

> In the future, no standards will be developed that require entities to follow regional reliability organization criteria or procedures, unless such criteria or procedures are approved by the ERO and the Commission. Additionally, NERC will be working with the regions to achieve greater consistency of requirements across the regions.[50]

NERC acknowledges and staff agrees that fill-in-the-blank standards will require significant work by the ERO, Regional Entities, and others in the industry to satisfy the requirements of section 215 of the FPA. NERC has developed a proposed timetable to address these issues.

F. Applicability of the NERC Standards

Section 215(b) of the FPA requires all "users, owners and operators of the Bulk-Power System" to comply with Commission-approved Reliability Standards. Each current NERC standard identifies entities to which the standard applies based on the NERC Functional Model. This model omits the categories of users, owners and operators, and it includes other categories of entities that are not users, owners or operators. These differences must be reconciled for a given proposed Reliability Standard in order to make it technically sound and legally enforceable.

In Order No. 672, the Commission stated:

> The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.[51]

Accordingly, each Reliability Standard must be explicit as to which entity it applies. However, the Applicability sections of the standards are not always sufficiently specific to be clear and unambiguous about the applicability of the standard. One problem with

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[49] Petition at 89.

[50] *Id.* at 89-90.

[51] Order No. 672 at P 325.

this lack of clarity occurs when a given type of entity may perform more than one of the functions covered by the standard depending on the circumstances.

G. Systems to Which the Standards Apply: Bulk Electric System v. Bulk-Power System

The differences between the definition of Bulk-Power System in section 215 of the FPA and the definition of Bulk Electric System found in the NERC Glossary upon which the NERC standards rely, create a problematic discrepancy that could create reliability gaps. This discrepancy, if left unaddressed, will interfere with maintaining reliability consistently across the Regions and may be inconsistent with Order No. 672. This gap could allow for some interconnected electric energy transmission networks, and electric energy from generating facilities needed to maintain transmission system reliability to be outside of the mandatory Standards.

The NERC Glossary defines the Bulk Electric System as follows:

> *As defined by the Regional Reliability Organization*, the electrical generation of resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[52]

When the task of defining the Bulk Electric System is delegated to each RRO, the result could be conflicting multiple definitions that subject different facilities to, or exclude different facilities from, the requirements of the standards.

Further, section 215(a)(1) defines Bulk-Power System as:

> Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.[53]

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[52] NERC Glossary of Terms Used In Reliability Standards at 2 (effective April 1, 2005) (emphasis added).

[53] Section 215(a)(1) of the FPA.

The FPA and NERC definitions obviously differ. The standards currently are applied only to the Bulk Electric System as defined by each Region. However, section 215(a)(3) of the FPA defines Reliability Standard as a requirement approved by the Commission to provide for reliable operation of the Bulk-Power System. The term Bulk Electric System does not appear to include all the system components from all non-distribution voltage levels, control systems, and electric energy from all generating facilities needed to maintain transmission system reliability included in the definition of Bulk-Power System.

IV. BAL: RESOURCE AND DEMAND BALANCING

A. Description and General Issues

NERC has six Resource and Demand Balancing (BAL) standards aimed at Balancing Authorities, Reliability Coordinators, RROs, Reserve Sharing Groups, Generator Operators, Transmission Operators, and Load Serving Entities.[54] These standards state the requirements to balance generation and load in order to maintain frequency of the Bulk-Power System within limits.

In general, the Measures, Compliance, and Requirements aspects of these standards may lead to different interpretations and inconsistent application. Of the six standards in this group, four do not list any criteria or factors to assess compliance with the Requirements or Levels of Non-Compliance that are required for the determination of enforcement penalties. In addition, one standard leaves the determination of actual Requirements to the RROs, leading to regional variations.

Below is a discussion of the primary issues of concern to staff, followed by an evaluation of individual standards in the context of these observations.

B. Primary Issues in the Resource and Demand Balancing Standards

1. Contingency Reserve Requirements

Contingency reserves are needed to compensate for the loss of generation resources so that the system frequency can be returned to 60 Hz. Specific Requirements concerning the composition of the reserves and the restoration time are left to Regions and sub-Regions to determine. For example, the following determinations are all left to individual Regions, sub-Regions, and Reserve Sharing Groups to make: the minimum reserve Requirement, the permissible mix of spinning and non-spinning operating reserve that may be included in Contingency Reserve, the procedure for applying Contingency Reserve in practice, any limitations on the amount of interruptible load, and what is counted toward spinning reserve. No specificity is provided concerning how these requirements are to be determined. Thus in some Regions large irrigation pumping and

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[54] The description of these entities, including their roles, tasks and relationships with other responsible entities are described in a document entitled "NERC Reliability Functional Model" that was approved by the Board of Trustees on February 10, 2004. There are three other relevant entities in addition to the entities identified above: Reliability Authority, Planning Authority and Resource Planner.

pumped hydro generation resources are permitted to be used as spinning reserve and in other Regions they are not.

2. Actual Frequency Response (Bias)

The frequency bias is a measure of the net power change for a 0.1 Hz change in frequency. The actual frequency bias is the net of the load frequency bias, which is mostly the result of the change in motor demand with changing frequency, and the generation frequency bias, which is a property of the type of generation and generator governor action. The actual bias will determine the post disturbance system frequency at which generation and load are again in balance. If the net bias is near zero, the post-disturbance frequency would settle to an unacceptably low and unstable level.

Area Control Error (ACE)[55] and the Control Performance Standards CPS1 and CPS2[56] are metrics that are used in gauging the performance of Balancing Authorities. Time Error Correction is a related metric but it is on an interconnection-wide basis. All of these metrics have Frequency Bias as one of their basic inputs. If the frequency bias used in the calculations is not the actual frequency bias, the metrics may not be measuring actual performance.

Staff notes that the size of a disturbance resulting in a net power change that would produce a 0.1 Hz change in the frequency in both the Eastern and Western Interconnections has decreased over the last 10+ years.[57] This is the opposite of what would be expected because each of the interconnections has grown in size. As the interconnections grow in size, it would be expected to take a larger disturbance and the resulting net power change to cause a 0.1 Hz frequency deviation.

The use of an inappropriate frequency bias setting may have an adverse impact on reliability. While these standards contain a Requirement to recalculate the frequency bias setting for the Balancing Authority's area annually, it also allows a default value of at

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[55] The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

[56] Control Performance Standard (CPS) is defined as the reliability standard that sets the limits of a Balancing Authority's control error over a specified time period. The CPS1 has a time period of one minute and CPS2 has a time period of ten minutes.

[57] NERC Resources Subcommittee (Frequency Task Force), *Frequency Response Standard Whitepaper* (2004), *at* http://www.nerc.com/pub/sys/all_updl/oc/rs/Frequency_Response_White_Paper.pdf. *See also* WECC Reserve Issues Task Force, *Frequency Response Standard White Paper* (2005), *at* http://www.wecc.biz/documents/library/RITF/FRR_White_Paper_v12_1-27-06.pdf.

least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.[58] Use of a frequency bias setting that is different than the actual net physical bias of the Balancing Authority's area could result in less control actions than are appropriate to preserve system reliability.

Staff notes that the requirement to determine the minimum frequency bias required and how the frequency bias should vary with generation to assure the reliability of the Bulk-Power System is not covered in the standards. It is a topic of discussion in the NERC Resource Subcommittee and an issue in various white papers.[59]

C. Concerns Specific to Individual Standards

Real Power Balancing Control Performance (BAL-001-0)

The purpose of this standard reads: "To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time."

Staff notes that this standard provides metrics that are useful in determining the performance of individual Balancing Authorities and uses these metrics in determining the Levels of Non-Compliance.

Disturbance Control Performance (BAL-002-0)

The purpose of this standard reads:

> The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of the DCS is limited to the loss of supply and does not apply to the loss of load.

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[58] Frequency bias settings are available at ftp://www.nerc.com/pub/sys/all_updl/oc/opman/CPS2Bounds_2005.pdf

[59] NERC Resources Subcommittee (Frequency Task Force), *Frequency Response Standard Whitepaper* (2004), *at* http://www.nerc.com/pub/sys/all_updl/oc/rs/Frequency_Response_White_Paper.pdf. *See also* WECC Reserve Issues Task Force, *Frequency Response Standard White Paper* (2005), *at* http://www.wecc.biz/documents/library/RITF/FRR_White_Paper_v12_1-27-06.pdf.

Requirement R3.1 requires that a Balancing Authority or Reserve Sharing Group carry at least enough contingency reserves to cover the most severe single contingency.[60] One interpretation of this requirement is that the most severe contingency is limited only to generation loss. However, a second, more stringent interpretation is that it can be applied to loss of supply which was the result of a transmission or generation contingency.

Further, the minimum percentage of spinning reserve required as part of the contingency reserve is not defined in the standard but is at the discretion of each RRO. Not having a minimum requirement could result in an entity "leaning on the system," which would result in an undue negative impact on competition.

Various regions have different definitions as to which resources are eligible to be counted as spinning reserves. For example, in some regions large irrigation pumping and pumped hydro resources are permitted to be used as spinning reserves, and in other regions they are not. There should be a sound technical basis for any such difference.

The standard states that a lower reporting threshold for the size of the minimum disturbance may be required by the RROs. To be enforceable, these lower reporting thresholds, along with their rationale, should be documented in the Regional Differences section.

Frequency Response and Bias (BAL-003-0)

The purpose of this standard reads: "To provide a consistent method for calculating the Frequency Bias component of ACE."

As discussed in section B2 above, the standard contains a Requirement to recalculate the frequency bias setting for the Balancing Authority's area annually, it also allows a default value of at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.[61] Use of a frequency bias setting that is different than the actual net physical bias of the Balancing Authority's area could result in less control actions than are appropriate to preserve system reliability.

The Measure identified in the standard requires the Balancing Authority to conduct Frequency Response surveys, but only if specifically requested to do so by the NERC Operating Committee. Further, once the Frequency Response survey is completed, there

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[60] *See* Standard BAL-002-2 (R3.1).

[61] Frequency bias settings are available at ftp://www.nerc.com/pub/sys/all_updl/oc/opman/CPS2Bounds_2005.pdf

is no requirement that the survey results be used to establish the Balancing Authority bias and there are no criteria or measures regarding how to apply the results of the survey.

The standard does not contain any Levels of Non-Compliance. NERC has not identified this standard as one that would be modified and resubmitted for Commission approval in November, 2006.

Time Error Correction (BAL-004-0)

The purpose of this standard reads: "To ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection."

The standard does not contain Measures to assure that all Balancing Authorities and Reliability Coordinators participate in achieving Time Error Corrections. Data from the NERC time error web page indicates that the efficiency of the Time Error Correction has significantly decreased over the last ten years.[62] Incomplete participation in time error correction can be measured by using this data. Participation in Time Error Correction requires change in generation output.

The standard does not contain any Compliance Measures or any Levels of Non-Compliance. NERC has not identified this standard as one that would be modified and resubmitted for Commission approval in November 2006.

Automatic Generation Control (BAL-005-0)

The purpose of this standard reads:

> To establish requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

One reliability goal of this standard is to assure that all the load and the generation within the Balancing Authority's boundary are balanced as measured by the ACE calculation. A

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[62] NERC, *Time Error Reports, at* http://www.nerc.com/~filez/timerror.html. Yearly data for total efficiency was 117 percent for 1996 and 65 percent for 2005. The calculation of efficiency by NERC in time error correction is the actual time change divided by the expected time change. If there is more participation than expected, the efficiency can be greater than 100 percent. The goal is to be near 100 percent efficiency.

second reliability goal is to assure that all generation and load is under the control of a Balancing Authority. The technical solution to this goal is to have control over adequate amounts and types of generation reserves and controllable load management resources.[63] Staff notes that this standard does not require either Generation Operators or Load-Serving Entities to provide AGC capabilities to the Balancing Authority. There is no requirement on how much AGC they must have at all times, or any subsequent verification process. This is a concern because there may not be adequate resources to maintain system frequency close to 60 Hz. Operation of the Bulk-Power System significantly different from the 60 Hz level can result in unintentional loss of firm load and generation resources.

The standard does not contain any Compliance Measures or any Levels of Non-Compliance. NERC has not identified this standard as one that would be modified and resubmitted for Commission approval in November 2006.

Inadvertent Interchange (BAL-006-0)

The purpose of this standard reads:

> To define a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

The standard includes specifications for reporting requirements, but no requirements to prevent a Balancing Authority from depending excessively on other Balancing Authorities over time. Data available from the NERC website indicates that the magnitudes of inadvertent interchange for some RROs in the Eastern Interconnection are increasing.[64]

The standard includes a single Level of Non-Compliance that is triggered if a Balancing Authority fails to report its inadvertent interchange by the 20th calendar day of the following month. There are no specific Measures in the standard concerning the reliability impact of large inadvertent interchange balances. NERC has not identified this

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[63] NERC Resources Subcommittee (Frequency Task Force), *Frequency Response Standard Whitepaper* (2004), *at* http://www.nerc.com/pub/sys/all_updl/oc/rs/Frequency_Response_White_Paper.pdf. *See also* WECC Reserve Issues Task Force, *Frequency Response Standard White Paper* (2005), *at* http://www.wecc.biz/documents/library/RITF/FRR_White_Paper_v12_1-27-06.pdf.

[64] NERC, *Inadvertent Interchange*, *at* http://www.nerc.com/~filez/inadv.html.

standard as one that would be modified and resubmitted for Commission approval in November 2006.

V. CIP: CRITICAL INFRASTRUCTURE PROTECTION

A. Description and General Issues

The Critical Infrastructure Protection group of reliability standards, as filed, consists of two standards aimed at establishing security for critical cyber assets and reporting occurrences of sabotage to the proper authorities. The first standard is CIP-001-0 Sabotage Reporting. The second standard is Urgent Action 1200 (UA-1200), which addresses the cyber security of bulk electric system assets. This group of standards applies to Reliability Coordinators, Balancing Authorities, Interchange Authorities, Transmission Service Providers, Transmission Operators, Generation Operators and Load-Serving Entities. The UA standard also applies to Interchange Authorities where appropriate.

In general, staff has concerns regarding measures, compliance, technical requirements and interpretation. CIP-001-0 does not include criteria or Measures to assess compliance with the Requirements of the standard or Levels of Non-Compliance that are required for enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

UA-1200, which relates to cyber security, provides some measures of compliance. However, these measures more often address the development or maintenance of documentation than the adequacy of the methods used or steps taken. A strong security standard should not only ensure that measures are in place, but also that those measures are effective. In the NERC petition, this Urgent Action standard was provided for information purposes only. The NERC Board of Trustees has since approved standards CIP 002-009 to replace this Urgent Action item. As approved by NERC, entities would be required to become compliant with the new CIP standards over the course of several years. However, the replacement standards have not yet been submitted to the Commission for approval.

Staff's examination indicates that the Requirements of both CIP standards may be incomplete and may be ambiguous regarding compliance requirements.

Below is a discussion of primary issues identified by staff and an evaluation of each CIP standard.

B. Primary Issues in the Critical Infrastructure Protection Cyber Security Standards

The cyber security standard, UA-1200, appears to establish requirements readily achievable by industry. However, the standard lacks detail and therefore creates for each applicable entity the discretion to set its own level of protection. As a result, security measures can vary widely from facility to facility. This lack of specificity makes it difficult to determine whether the standard reduces risks to the reliability of the Bulk-Power System from any compromise of cyber security assets.

The cyber security standard requires entities to identify and catalog assets and procedures. However, except for provisions addressing the monitoring of physical and electronic access, the standard does not require entities to assess vulnerabilities of their assets and procedures, nor are applicable entities required to address identified vulnerabilities.

C. Concerns Specific to Individual Standards

Sabotage Reporting (CIP-001-0)

The purpose of this standard reads: "Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies."

The standard requires that each Reliability Coordinator, Balancing Authority, Transmission Operator, Generation Operator and Load-Serving Entity: (1) have procedures for the recognition of and for making their operating personnel aware of sabotage events; (2) have procedures for the communication of information concerning sabotage events to appropriate "parties" in the interconnection; (3) provide operating personnel with guidelines for reporting disturbances due to sabotage events; and (4) establish communications contacts with applicable government officials and develop appropriate reporting procedures. While applicable entities must establish communication contacts, there is no requirement in the standard that an entity actually contact a governmental or regulatory body in the event of sabotage.[65] Thus, the failure to follow the procedures developed by an entity would not result in a violation of this standard.

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[65] *But see* Standard EOP-004-0 (requiring entities to report actual or suspected physical or cyber attacks to the U.S. Department of Energy Operations Center). Reference to these related requirements in the CIP-001 standard could prove useful to regulated entities.

Further, the standard does not define "sabotage." Thus, a cyber attack that gains access to a control room but does not cause damage may be reported by some entities but not be reported by others if it does not meet their understanding of the term "sabotage."[66]

Finally there are no Measures described that could be used to assist an entity in determining how to achieve the Requirements, nor are there any degrees of compliance described that could be used to measure compliance with the standards or enforce them in a meaningful way. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Urgent Action 1200 (UA 1200)

This cyber security standard is composed of 16 sections that discuss various aspects of cyber security. Even though NERC's Board of Trustees has officially terminated UA 1200 as of June 1, 2006, comments on this standard are included here to address the important area of cyber security.

In general, the standard's Requirements are imprecise, making it difficult to ascertain whether or not an entity was in compliance with the various provisions contained within each section. In addition, the Requirements in several sections rely on full compliance with other cyber security sections. Because success of the cyber security standard depends on full implementation of all the sections, enforcement and compliance assurance take on added importance.

A related issue concerning the cyber security standard arises from NERC's published implementation plan. This plan states that compliance with the cyber security standard will be conducted entirely through a self-certification process. Neither NERC nor the regions will conduct audits to verify self-certifications, and neither NERC nor the regions will issue letters of non-compliance or monetary penalties to those who indicate in their self-certification that they are not in compliance.[67] These statements contradict provisions in each section of the standard which require certain documentation to be available for inspection and which state that sanctions will consist of letters for non-

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[66] While UA-1200 defines "Cyber Security Incident" as "[a]ny event or failure (malicious or otherwise) that disrupts the proper operation of a critical cyber asset," it is not clear whether this definition applies to CIP-001-0 as well. If applicable, this definition may actually lower the reporting requirements where a known penetration occurs but does not disrupt operations.

[67] NERC, Implementation Plan, Second Renewal of Urgent Action Cyber Security Standard (June 2005).

compliance.[68] As noted above, without strong enforcement and compliance provisions, assuring implementation of the cyber security standard will be difficult. The following discussion pertains to the individual sections that comprise UA 1200, as provided in NERC's petition for information purposes.

Section 1201 – Cyber Security Policy

This section requires the creation and maintenance of a cyber security policy. It further requires designation of a senior manager to be responsible for this policy and to authorize any deviations. It also requires that the justifications for any deviations from the policy be documented. However, the Requirement to create a policy is vague; there is no detail regarding what issues or concerns the cyber security policy should address. The Measures for this section all address development and maintenance of documentation, *e.g.*, the identification of the senior manager responsible, the annual review of the policy and the documentation for the deviations from the policy. There are no Measures that address the adequacy of the policy. In the NERC submission this Urgent Action standard was provided for information only.

Section 1202 – Critical Cyber Assets

This section requires that an entity identify its critical cyber assets, document these assets, and update this documentation at least annually or within 90 days of any changes to the critical cyber assets. The definition of "critical cyber assets" is imprecise, making it difficult for an entity to determine what cyber assets are "critical" and therefore governed by UA-1202.[69] It is probable that two different entities could designate the same type of asset differently. The measures for this section all address development and maintenance of documentation, *i.e.*, the development of the critical cyber asset document, and the annual review of the document. There are no compliance measures that address the adequacy of the selection of the assets themselves.

Section 1203 – Electronic Security Perimeter

This section requires that an entity identify an electronic perimeter around its critical cyber assets and maintain documentation of the perimeter, all interconnected cyber assets, and all electronic access points. This information must be updated at least

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[68] North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standard UA-1200 (Standard UA-1200).

[69] *Id.* (The Standard defines "Critical Cyber Assets" as "(t)hose computers, including installed software and electronic data, and communication networks that support, operate, or otherwise interact with the bulk electric system operations. This definition currently does not include process control systems, distributed control systems, or electronic relays installed in generating stations, switching stations and substations.").

annually or within 90 days of any changes to the network. The standard contains a definition of "Electronic Security Perimeter," but there is little clarity on how an electronic perimeter is identified.[70] Also, there is little specificity about how to determine what is an "electronic access point." For example, an "access point" could mean an "interactive access point" where a user is prompted for a password, or it may include any electronic access, such as an application communications port. The Measures for this section all address development and maintenance of documentation, *e.g.*, the development of the electronic security perimeter document and annual review. There are no Measures that address the adequacy of the method used to determine the electronic security perimeter.

Section 1204 – Electronic Access Controls

This section requires an entity to identify and implement electronic access controls for access to critical cyber assets within the electronic security perimeter. The entity is to maintain documentation of the electronic access controls and update it at least annually or within 90 days of any changes to the electronic security perimeter or the electronic access controls. However, there is no detail as to the functionality or any specific measures that the electronic access controls should address. Therefore, almost any electronic access control, good or bad, would satisfy this requirement. The Measures for this section all address development and maintenance of documentation, *i.e.*, the documentation of the electronic access controls, and the annual review of this document. There are no Measures that address the adequacy of the methods used to provide the electronic access controls.

Section 1205 – Physical Security Perimeter

This section requires an entity to identify its physical security perimeter for the protection of critical cyber assets and document the perimeter and all access points. This information must be updated at least annually or within 90 days of any modification of the network. The section does not identify the level of rigor that a physical security perimeter should exhibit. The Measures for this section all address development and maintenance of documentation, *i.e.*, the documentation of the physical security perimeter, and the annual review of this document. There are no Measures that address the adequacy of the perimeter itself.

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[70] *Id.* (The standard defines "Electronic Security Perimeter" as "(t)he border surrounding the network or group of sub-networks (the 'secure' network) to which the critical cyber assets are connected.").

Section 1206 – Physical Access Controls

This section requires an entity to identify and implement physical access controls for access to critical cyber assets within the physical security perimeter. The entity must keep documentation identifying the physical access controls. This information must be updated at least annually or within 90 days of any changes to the physical security perimeter or physical access controls. There is no detail provided that would assist an entity in determining features or functionality of a good physical access control system. The Measures for this section all address development and maintenance of documentation, *i.e.*, the documentation of the physical access control, and the annual review of this document. There are no Measures that address the adequacy of the physical access controls themselves.

Section 1207 – Personnel

This section requires the entity to maintain a list of all personnel who are authorized to have electronic or physical access to critical cyber assets. Entities are required to update the list at least quarterly or within 24 hours of any change. This section requires the entity to conduct background screening of all personnel in accordance with federal, state, provincial, and local laws. This section requires that the level of screening be consistent with the degree of access granted. The Measures for this section all address development and maintenance of documentation, *i.e.*, the documentation of the personnel access list, and the quarterly review of this document. There are no Measures that address the adequacy of the personnel screening.

Section 1208 – Monitoring Physical Access

This section requires an entity to continuously monitor physical access to critical cyber assets. The entity is to document the tools and procedures used to monitor physical access and also verify in its documentation that these tools and procedures are functioning and being used as planned. The entity is also required to maintain for six months records (*e.g.*, logs) of physical access to critical cyber assets and verify those records against the list of access control rights. While the verification requirement is a positive aspect of this section, there is limited specificity in the standard regarding what tools and procedures should be used to monitor physical access, suggesting that a minimum standard such as video surveillance or other physical monitoring can be used as a means to actually control access or to verify who received access.

Section 1209 – Monitoring Electronic Access

This section requires an entity to continuously monitor electronic access to critical cyber assets. The entity is to document the tools and procedures used to monitor electronic access and also verify in its documentation that these tools and procedures are functioning and being used as planned. The entity is also required to maintain for six months records (*e.g.*, logs) of electronic access to critical cyber assets and verify those records against the list of access control rights. The section does not specify what tools and procedures are appropriate to monitor electronic access. The requirement to verify that tools and procedures are being used as planned is a positive aspect of this section.

Section 1210 – Information Protection

This section requires an entity to protect information associated with critical cyber assets as well as the policies and practices used to keep them secure. The entity is required to maintain a document identifying access limitations to sensitive information related to critical cyber assets. This document must address procedures, critical cyber asset inventories, maps, floor plans, equipment layouts, and configurations, and is to be reviewed and updated at least annually. There is some detail as to what an adequate information protection scheme should encompass.

Section 1211 – Training

This section requires an entity to develop and maintain a training program on cyber security policy, physical and electronic access controls to critical cyber assets, the release of cyber critical asset information, potential threat incident reporting, and action plans and procedures to recover or reestablish critical cyber assets following a cyber security incident. Training is to be conducted upon initial employment and reviewed annually. The Measures for this section all address development and maintenance of documentation, *i.e.*, documenting successful completion of the training. There are no Measures that address the adequacy of the training itself.

Section 1212 – Systems Management

This section requires an entity to establish system management policies and procedures for configuring and securing critical cyber assets. The entity is required to document these policies and procedures and update them at least annually. According to this section, the policies and procedures at a minimum should address password management, computer account authorization, disabling unused accounts, disabling unused network ports and services, secure dial-up modems, firewall management, intrusion detection processes, security patch management, anti-virus software, retention of logs, and the identification of vulnerabilities and responses to same. The section is unclear about how entities ensure the adequacy of the efforts in any of these areas. The Measures for this section all address development and maintenance of documentation, *i.e.*, the documentation of the policies and procedures. There are no Measures that address the adequacy of any of the policies or procedures themselves.

Section 1213 – Test Procedures

This section requires an entity to establish test procedures and acceptance criteria to assure that critical cyber assets installed or modified comply with the security requirements in this standard. The section requires that testing be conducted in an isolated test environment and that the test procedures and acceptance criteria must be documented. There is no detail on establishing proper test procedures or acceptance criteria. The Measures for this section all address development and maintenance of documentation, *i.e.*, the documentation of the policies and procedures. There are no Compliance Measures that address the adequacy of any of the testing procedures themselves.

Section 1214 – Electronic Incident Response Actions

This section requires entities to define and document electronic incident response actions, including roles and responsibilities assigned by individual or job function. Aside from detailing reporting procedures to the Information Sharing and Analysis Center, there is little detail on establishing internal response actions. There is some information as to the types of incidents that should be reported based on the *Indications, Analysis & Warning Program Standard Operating Procedure* that is referenced in the section.[71]

Section 1215 – Physical Incident Response Actions

This section requires entities to define and document physical incident response actions, including roles and responsibilities assigned by individual or job function. Aside from detailing reporting procedures to the Information Sharing and Analysis Center, there is little detail on establishing internal response actions. There is some information regarding the types of incidents that should be reported based on the *Indications, Analysis & Warning Program Standard Operating Procedure* that is referenced in the section.[72]

Section 1216 – Recovery Plans

This section requires entities to create action plans and procedures to recover or re-establish critical cyber assets following a cyber security incident and to maintain a document defining the plan and procedures. The entity should exercise these plans and procedures at least annually and document those exercises as well. There is no detail regarding what features and functionality should be incorporated in the recovery plan. The Measures for this section address development and maintenance of documentation, *i.e.*, the documentation of the recovery plan. There are no Compliance Measures that address the adequacy of the recovery plans and procedures themselves.

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[71] National Infrastructure Protection Center, Indications, Analysis & Warning Program Standard Operating Procedure (2002).

[72] *Id.*

VI. COM: COMMUNICATIONS

A. Description and General Issues

The two Communication (COM) standards apply to Reliability Coordinators, Transmission Operators, Generator Operators and Balancing Authorities. The first standard requires that these entities have adequate internal and external telecommunications facilities for the exchange of Interconnection and operating information necessary to maintain reliability. The second standard requires that these facilities be staffed and available for addressing real-time emergencies and that effective communications be carried out between operating personnel.

Generally speaking, these standards raise issues from the standpoint of Measures, Compliance and Requirements. Further, these standards do not include recommendations from the Blackout Report and contain instances of ambiguity.

These standards do not contain any specification of Measures and Compliance to assess an entity's compliance with the Requirements. They also do not contain the Levels of Non-Compliance. NERC has indicated that these standards will be modified to address this deficiency and resubmitted for Commission approval in November 2006. Implementation of the Blackout Report recommendations regarding reliability involves these standards.

Set forth below is a discussion of primary issues and an evaluation of individual standards in light of these observations.

B. Primary Issues in the Communications Standards

1. Unclear Requirements in Telecommunications Facilities

Telecommunications facilities are an integral part of a complex set of operating tools necessary for all system operators to be continuously aware of emerging system conditions, to communicate with other operating entities, and to direct, coordinate and receive operating instructions to maintain system reliability. The first COM standard contains a general requirement to provide "adequate and reliable" telecommunications facilities for all applicable operating entities. It has a redundancy and diverse routing requirement, but it is effective only "where applicable," and no specification is provided regarding the circumstances where the requirement would in fact be applicable. There are no specific or minimum requirements on adequacy, redundancy and diverse routing of the telecommunications facilities necessary to ensure the exchange of operating information, both internally and among the operating entities.

To perform their real-time operational responsibilities properly, Reliability Coordinators need telecommunications facilities beyond those required by other operating entities. The particular needs of Reliability Coordinators are not addressed in the standards. In addition, leaving the specification of what constitutes adequate and reliable telecommunication facilities to operating entities without defining a minimum requirement based on their respective responsibilities may create ambiguities; operating entities could claim to be in compliance with the standard and still may not have adequate telecommunications facilities for use during real-time normal and emergency operations.

2. Ineffective Communications and Inadequate Coordination Can Threaten Reliability

Effective communications with proper communications protocols among the operating entities are essential for maintaining reliable system operations. The Blackout Report emphasized this principle using the following example:

> On August 14, 2003, reliability coordinator and control area communications regarding the conditions in northeastern Ohio were in some cases ineffective, unprofessional, and confusing. Ineffective communications contributed to a lack of situational awareness and precluded effective actions to prevent the cascade.[73]

The Blackout Report cited ineffective communications as a factor common to the August 14 blackout and other previous major outages in North America.[74]

Moreover, Recommendation Number 26 of the Report instructs NERC, working with Reliability Coordinators and Control Area Operators, to "[t]ighten communications protocols, especially for communications during alerts and emergencies. Upgrade communication system hardware where appropriate."[75]

Staff interprets this Blackout Report recommendation's reference to "effective communications" with "tightened communications protocols" among operating entities to include two key components: (i) effective communications that are delivered in clear language via pre-established communications paths among pre-identified operating entities, and (ii) communications protocols which clearly identify that any operating

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[73] Blackout Report at 161 (Lack of situational awareness can result from the following: ineffective communications, inadequate reliability tools and inadequate operator training).

[74] *Id.* at 107.

[75] *Id.* at 141, 161.

actions with reliability impact beyond a local area or beyond a Reliability Coordinator's area must be communicated to the appropriate Reliability Coordinator for assessment and approval prior to their implementation to ensure reliability of the interconnected systems.[76]

NERC's second COM standard, titled "Communication and Coordination," requires:

> Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.
>
> Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner ....[77]

Staff notes that these requirements fulfill the "effective communications" component of the Blackout Report recommendation, but do not meet the call for "tightened communications protocols", as discussed above. These Requirement provisions do not contain a requirement that the appropriate operating actions in normal and emergency operating conditions that may have reliability impact beyond a local area or Reliability Coordinator's area must be assessed and approved by the Reliability Coordinator, before being implemented by the operating entities. Some parties may suggest that the "assessment and approval" component is not considered as communications protocols and should instead be included as part of other relevant standards, such as the IRO or TOP standards. Staff agrees that this "assessment and approval" system of checks and balances to ensure reliability of the interconnected systems could be embedded as an important operating practice for the IRO and TOP protocols. Since this requirement is not explicitly included in the existing standards, Staff believes the most important need at this juncture is that it appears somewhere in the Reliability Standards.

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[76] *See* NERC Glossary at 13 (defining Reliability Coordinator as "the entity with the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations…").

[77] North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standard COM-002-1 Requirements R.1.1 and R.2.

C. Concerns Specific to Individual Standards

Telecommunications (COM-001-0)
The purpose of this standard reads:

> Each Reliability Coordinator, Transmission Operator and Balancing Authority needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.

The standard does not contain specific or minimum adequacy, redundancy and diverse routing requirements for telecommunications facilities. Such specificity may vary depending upon whether the entity has a major impact on the system reliability. Such entities would have additional redundancy and diverse routing requirements. Staff notes that the Compliance Element Standards Drafting Team had similar comments concerning some of the requirements.

The applicability section does not specify that Generation Operators are subject to telecommunications requirements set forth in the standard. This may have the effect of exempting Generation Operators from the standard or at least complicating the task of applying it to them.

The standard contains no Compliance Measures or Levels of Non-Compliance. Without Compliance Measures and Levels of Noncompliance, the ERO will not have norms that are specific enough to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Communication and Coordination (COM-002-1)
The purpose of this standard reads:

> To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.

This standard does not contain a Requirement that appropriate operating actions be assessed and approved first and then implemented in normal and emergency operating conditions in which reliability could be impacted beyond a local area. This concern is discussed in section B.2 above. In situations where reliability impacts on one area could potentially affect the footprint of a Reliability Coordinator and its neighboring footprints, operating actions taken by a Balancing Authority or Transmission Operator should require assessment and approval by their Reliability Coordinator and notification of the actions to the neighboring footprints to ensure reliability of the interconnected systems.

The standard does not contain any Compliance Measures or Levels of Non-Compliance. Without Compliance Measures and Levels of Non-Compliance, the ERO will not have norms that are specific enough to implement consistent and effective enforcement.

NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006. Standard COM-002-1 was recently approved by the NERC Board of Trustees with an effective date of November 1, 2006.

VII. EOP: EMERGENCY PREPAREDNESS AND OPERATIONS

A. Description and General Issues

The Emergency Preparedness and Operations (EOP) group of reliability standards includes nine standards that are applicable to one or more of seven NERC-defined entities.[78] These standards address preparation for emergencies, necessary actions during emergencies, system restoration and reporting after disturbances have occurred.

In general, these standards raise issues in the Measures, Compliance, and Requirements sections. Further, these standards include instances of ambiguity. Five of the nine standards include some Measures to assess compliance, while four have no Compliance Measures. Six standards have some Levels of Non-Compliance that are required for enforcement and three standards have no compliance levels described. NERC has indicated that some these standards will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

An examination of the Requirements has identified six standards that have significant technical issues either because they may be incomplete or lack specificity or because they do not address knowledge gained from past experience. Implementation of the Blackout Report recommendations regarding reliability involves standards EOP-002, EOP-003, and EOP-008 in this group.

Below follows a discussion of primary issues and an evaluation of individual standards in the context of these observations.

B. Primary Issues in the Emergency Preparedness and Operations Standards

1. Definition of Emergency States: Normal, Alert and Emergency

System operators need common definitions for normal, alert, and emergency states to enable them to act appropriately and consistently as system conditions change. Alert and emergency states may result from either resource deficiencies and/or transmission contingencies. The Blackout Report states that

[78] These entities are: Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, Generator Owners, Load Serving Entities, and Regional Reliability Organizations.

> On August 14, the principal entities involved in the Blackout did not have a shared understanding of whether the grid was in an emergency condition, nor did they have a common understanding of the functions, responsibilities, capabilities, and authorities of reliability coordinators and control areas under emergency or near-emergency conditions.[79]

To address this concern, Recommendation Number 20 of the Blackout Report recommended establishing "clear definitions for normal, alert and emergency operational system conditions."[80] It also recommended clarifying "roles, responsibilities and authorities of reliability coordinators and control areas under each condition."[81] This group of standards does not clearly define transmission-related system states, entry conditions for alert and emergency states, or who has the authority to declare them.[82]

2. Load Shedding: Specific Amounts and Timing

Shedding of firm load is an operating measure of last resort to contain system emergencies and prevent cascading. The system operators must have the capability to manually or automatically shed load in a timely manner to return the system to a stable condition. The Blackout Report states that

> The investigation team concluded that since the Sammis-Star 345 kV outage was the critical event leading to widespread cascading in Ohio and beyond, if manual or automatic load-shedding of 1,500 MW had occurred within the Cleveland-Akron area before that outage, the blackout could have been averted.[83]

However, it should be noted that at that time there were no automatic or quick-acting manual load shedding capabilities in the area. While these standards require Transmission Operators and Balancing Authorities to have the capability to shed load in a timeframe adequate for responding to an emergency, they do not specify the minimum

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[79] Blackout Report at 158.

[80] *Id.*

[81] *Id.*

[82] *See* NYISO Emergency Operations Manual (July 2005) (For an example of transmission-related normal, alert and emergency states) at: http://www.nyiso.com/public/webdocs/documents/manuals/operations/em_op_mnl.pdf.

[83] Blackout Report at 70.

capability that must be provided and the maximum allowable delay before load shedding can be implemented.[84]

3. Operator Protection for Load Shedding

While the current standards provide operators with the authority to shed load to respond to an emergency and return the system to a stable state, the operators may hesitate to initiate such actions in appropriate circumstances without assurances that they will not be subject to liability or retaliation, even if their action is in accordance with previously approved guidelines. Recognizing the importance of this issue, the Blackout Report Recommendation Number 8 recommends that operators who initiate load shedding pursuant to approved guidelines should be shielded from liability or retaliation.[85] The current standards do not require that these safeguards be provided to shield operators from retaliation when they declare an emergency or shed load. Staff notes that NERC readiness audits seek confirmation that such protection is provided to the operators by their employers. Staff believes this is a positive step, but not a substitute for addressing this issue in the standards.

4. Back-Up Capability

The primary control center may become inoperable either as a result of the need to evacuate the control center – for example, because of some environmental or security threat – or because of damage to the control center facilities due to natural or man-made disasters. In the former case, back-up capabilities may rely on the critical functionalities (data, tools, voice) of the primary control center. In the latter case, however, the back-up capabilities must be completely independent of the primary control center to ensure continued reliable operations. While evacuations may require back-up capability only for a few hours or days, damage to the primary control center may require operation from back-up capabilities for a prolonged period of time, possibly measured in months. Failure to provide adequate back-up capability and periodically test its effectiveness, and failure to periodically test the competency of operators to function from the back-up capability can have serious reliability impacts should the primary control center become inoperable for a prolonged period of time. These standards do not address the

[84] This contrasts sharply with the criteria of the Northeast Power Coordinating Council (NPCC). NPCC Emergency Operation Criteria Document A-03 requires that "[e]ach Area must be capable of manually shedding at least fifty percent of its load in ten minutes or less. In so far as practical, the first half of the load shed manually should not include load which is part of any automatic load shedding plan."

[85] Blackout Report at 147.

requirements for independence from the primary control center, provide for prolonged operation or provide the minimum tools and facilities consistent with the roles, responsibilities and tasks of the different entities. Staff recognizes, however, that when addressing back up capability for prolonged periods, the standards should reflect an appropriate balance between the probability of needing such back up capability and the consequences to reliability of not having back up capability.

C. Concerns Specific to Individual Standards

Emergency Operations Planning (EOP-001-0)

The purpose of this standard reads:

> Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

The standard requires Transmission Operators and Balancing Authorities to develop, maintain, and implement a set of plans to mitigate operating emergencies resulting from either insufficient generation or transmission. There is no similar requirement for Reliability Coordinators, who are the highest level of authority responsible for the Bulk-Power System.

The standard requires "the [Transmission Operators] to implement load reduction in sufficient amount and time to mitigate IROL violations before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes."[86] One interpretation of this requirement is that power transfers must be adjusted within 30 minutes to relieve IROL overloads. Another interpretation is that load reduction - interpreted as load shedding - must be capable of being implemented within 30 minutes after an operating emergency is declared. The latter interpretation could lead to an inappropriate conclusion that load shedding capability with an implementation time of up to 30 minutes is acceptable to deal with system emergencies. This could expose the system to higher risk since load shedding is the option of last resort and must be capable of being implemented in a much shorter time period than 30 minutes.

[86] Standard EOP-001-0 (R2).

The standard does not define transmission-related "normal," "alert," and "emergency" states, provide criteria for entering into these states, or identify authority for declaring these states as discussed in the Primary Issues section above.

Capacity and Energy Emergencies (EOP-002-1)

The purpose of this standard reads: "To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies."

The standard addresses responsibility, authority and actions to be taken to alleviate generation capacity and energy emergencies. It does not address emergencies resulting from insufficient transmission capability nor is this issue addressed elsewhere in other standards. Staff notes that TLRs are not appropriate for addressing actual transmission emergencies since they are "not fast and predictable enough for use in situations in which an operating security limit is close to or actually being violated" as stated in the Blackout Report[87] and discussed further in section B.4 of the IRO Chapter , regarding IRO: Interconnected Reliability Operations and Coordination.

Load Shedding Plans (EOP-003-0)

The purpose of this standard reads:

> A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

This standard requires that, after taking all other remedial steps, load be shed rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. However, the standard does not specify the minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented. This issue was explained in greater detail in the Primary Issues section above.

Blackout Report Recommendation Number 8 recommends that operators who initiate load shedding pursuant to approved guidelines should be shielded from liability of retaliation.[88] The standard does not require that safeguards be provided to shield operators from retaliation when they declare an emergency or shed load in accordance with previously approved guidelines. Staff notes that NERC readiness audits seek

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[87] Blackout Report at 163.

[88] Blackout Report at 147.

confirmation that such protection is provided to the operators by their employers. As indicated, this is a positive step but not one that is a substitute for a standard with full clarity on this issue.

The standard does not require periodic drills of simulated load shedding (not actual shedding of firm load). Periodic simulated drills are important to test the effectiveness of the processes, communications and protocols, and to familiarize operators from Reliability Coordinators, Transmission Operators and Load Serving Entities with their respective roles and responsibilities associated with the load shedding plans.

The standard does not contain any Measures to assess compliance with any of the Requirements of the standard or any Levels of Non-Compliance required for enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Disturbance Reporting (EOP-004-0)
The purpose of this standard reads:

> Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.

The standard does not address the Blackout Report's Recommendation Number 14: "Establish a standing framework for the conduct of future blackout and disturbance investigations."[89] Staff notes that a presentation by the Department of Energy, *Preparing For the Next Blackout*,[90] was given to the NERC Board of Trustees in February 2005. Their presentation lays out steps to prepare for an investigation, priority actions to take immediately after a blackout and the process to follow during the investigation. Staff also notes that NERC has prepared a procedure for responding to major events that affect the Bulk Electric System entitled "NERC Blackout and Disturbance Response Procedures."[91] The staff believes that the DOE presentation and the NERC procedure provide a reasonable basis for revising the standard.

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[89] Blackout Report at 149.

[90] Silverstein, Alison, Preparing for the Next Blackout, February 7-8, 2005 at http://www.nerc.com/~filez/botmin.html (Presentations at NERC Board of Trustees, Stakeholders Committee and Annual Meeting of Members).

[91] *See NERC's Application for Certification as the Electric Reliability Organization, Rules of Procedure of the Electric Reliability Organization, NERC Blackout and Disturbance Response*

(continued)

The standard does not contain any Measures to assess compliance with any of the Requirements of the standard or any Levels of Non-Compliance required for enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

System Restoration Plans (EOP-005-0)

The purpose of this standard reads: "To ensure plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system."

The standard requires a restoration plan to reestablish the electrical system in a stable and orderly manner in the event of a partial or total shutdown. While the standard requires that operators be trained in the implementation of the restoration plan, it does not require this to be done periodically.

The standard contains Levels of Non-Compliance but no Measures to assess compliance with any of the Requirements of the standard. NERC has not identified this standard as one that would be modified and resubmitted for Commission approval in November 2006.

Reliability Coordination-System Restoration (EOP-006-0)

The purpose of this standard reads: "The Reliability Coordinator must have a coordinating role in system restoration to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection."

Staff notes that this standard requires only that Reliability Coordinators, the highest authority responsible for overall system restoration, be aware of the restoration plan of each Transmission Operator in its Reliability Coordination Area, but not that they be involved in its development or approval.

The standard does not contain any Measures to assess compliance with the Requirements of the standard or any Levels of Non-Compliance required for enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Procedures, Appendix 8 *available at* ftp://www.nerc.com/pub/sys/all_updl/ero/application/ERO-Application-Complete.pdf.

Establish, Maintain, and Document a Regional Blackstart Capability Plan (EOP-007-0)

The purpose of this standard reads:

> A system Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans (SRP).

RRO is listed as the Applicability entity in this standard and its appropriateness is a concern in the new mandatory standard structure.

Plans for Loss of Control Center Functionality (EOP-008-0)

The purpose of this standard reads: "Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable."

The standard requires a backup plan but does not specifically require that back-up capabilities be provided. As discussed in the Primary Issues section B4 above, this standard does not address the requirements for independence from the primary control center, provide for prolonged operation or provide the minimum tools and facilities consistent with the roles, responsibilities and tasks of the different entities.

Documentation of Blackstart Generating Unit Tests Results (EOP-009-0)

The purpose of this standard reads:

> A System Blackstart Capability Plan (BCP) is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional System Restoration Plans.

The standard requires that the start-up and operation of each generating Blackstart unit be tested and the results submitted to the RRO. However, it does not require the Blackstart units to be periodically tested to ensure that they will be available when required to restore the system.

VIII. FAC: FACILITIES DESIGN, CONNECTIONS, MAINTENANCE, AND TRANSFER CAPABILITIES

A. Description and General Issues

The nine Facility (FAC) standards apply to Generator Owners, Transmission Owners, Distribution Providers, Load-Serving Entities, Transmission Planners, Planning Authorities, Reliability Coordinators, and RROs. Of the nine standards in this group, two address facility connection and coordination requirements, one addresses vegetation management, and four address processes to determine facility ratings and use in system modeling. Two new standards address transfer capabilities methodology.

In general, the FAC standards raise issues concerning the sufficiency of measures, the lack of compliance directives, and ambiguities in interpreting the technical Requirements. Two standards in this group may raise technical issues related to safety and reliability aspects of the Bulk-Power System. Two standards in this group may not contain sufficient criteria to assess Compliance. Several of these standards may not address the lessons learned from past operating incidents or may not contain technically sound means to achieve the specified reliability goal.

Staff notes that several standards in this group address separate matters but have identical purpose statements. Generally, staff suggests such statements be augmented or tailored to reflect the specific aspect of the purpose the given standard is designed to achieve.

Implementation of the Blackout Report recommendations regarding reliability involves standards FAC-003 and FAC-008 in this group. Below is a discussion of primary issues evident in the FAC standards as well as an evaluation of the individual standards in the context of these observations.

B. Primary Issues in the Facility Standards

1. Consistency of Facility Standards with the Commission's Generation Interconnection Orders[92]

System assessments are required to ensure that facilities can be interconnected to the system to supply load reliably under normal and contingency conditions. The FAC standards require system performance assessments in accordance with reliability standard TPL-001-0, which relates only to normal system conditions.[93] Staff notes that Order No. 2003[94] requires assessments of both normal and post-contingency conditions and therefore is more rigorous than TPL-001-0.

2. Vegetation Management

Improper vegetation management is a recurring causal factor in large-scale power outages, including the August 14, 2003 blackout.[95] In response to the Blackout Report, NERC adopted a Version 1 vegetation management standard which became effective on April 7, 2006. Staff commends the industry for adopting a vegetation management standard that employs a performance metric, but has several significant concerns regarding the standard. These concerns reflect the recommendations that the

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[92] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005); *see also Notice Clarifying Compliance Procedures*, 106 FERC ¶ 61,009 (2004); *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180 (2005), order on *reh'g*, Order No. 2006-A, 113 FERC ¶ 61,195 (2005); *see also Standardization of Small Generator Interconnection Agreements and Procedures, Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,572 (2003); *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186 (2005), *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[93] Standard TPL-001-0 (Requirement 1 states that "The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands …").

[94] Order No. 2003-A at P 89 and 145 (Transmission Owners have made compliance filings with the Commission for Large Generation Interconnection Procedures and Agreements, known as LGIP and LGIA respectively).

[95] Blackout Report at 107 ("The factors that were common to some of the major outages above and the August 14 blackout include: (1) conductor contact with trees …").

Commission submitted to Congress in September 2004 in a report on Vegetation Management on how the electric industry could improve vegetation management practices.[96]

First, the current standard does not designate maximum allowable inspection intervals. Rather, each Transmission Owner is responsible for maintaining a formal transmission vegetation management program that defines a schedule for and the type of right of way vegetation inspections (*e.g.*, aerial, ground). Thus, a Transmission Owner cannot be faulted for the length of its inspection interval, provided that it has defined the schedule in its formal program.[97]

Second, the current standard may use a minimum clearance based on an IEEE standard that is not sufficient.[98] The Version 1 vegetation management standard requires a Transmission Owner to determine and document the minimum allowable clearance between energized conductors and vegetation before the next trimming, and it specifically provides that "Transmission-Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*)."[99] However, IEEE Standard 516-2003 is intended for use by highly-trained maintenance personnel to carry out live-line work using specialized tools under controlled environments and operating conditions. The allowable clearances in the IEEE standard are significantly lower than those specified by the relevant U.S. safety codes. For example, the IEEE's standard specifies a 2.45-foot clearance from a live conductor for the 120 kV voltage class,[100] whereas the ANSI Z-133 standard specifies 12-feet, 4-inches as the approach distance for the 115 kV voltage class.[101] Therefore, use of the IEEE clearance provision as a basis for minimum clearance prior to the next tree trimming may

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[96] Utility Vegetation Management and Bulk Electric Reliability Report at 17 (September 7, 2004).

[97] *See* North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standard FAC-003-1, Requirement R1.1 (Standard FAC-003-1).

[98] Blackout Report at 154 (Recommendation Number 16 is to "(e)stablish enforceable standards for maintenance of electrical clearances in right-of-way areas.").

[99] Standard FAC-003-1 (R1.2.2).

[100] Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 516-2003, IEEE Guide for Maintenance Methods at 20.

[101] ANSI Z133, American National Standards Institute Standard For Tree Care Operations – Pruning, Trimming, Repairing, Maintaining and Removing Trees, and Cutting Brush – Safety Requirements.

not be appropriate, and adopting it for use with regular maintenance practices in vegetation management may be a "lowest common denominator" approach. Widespread implementation of this approach could inadvertently subject the public to more hazardous conditions. In addition, use of IEEE Standard 516-2003 could create the unintended consequence that some transmission owners who currently maintain more stringent vegetation management programs based on standards such as the ANSI Z-133 may relax their practices to meet the less-stringent minimum requirement set forth in the NERC vegetation management standard FAC-003-1..

Staff is not necessarily recommending use of the ANSI Z-133 standard as the minimum standard; however, we seek comment on whether the IEEE standard is sufficient to maintain reliability and protect public safety and, if not, what modifications to that standard should be made or whether an alternative standard is required to satisfy Order No. 672.

3. Methodology to Determine Facility Ratings

Under current utility practices, there is no uniform set of methodologies that are used by the reliability and operating entities to determine equipment ratings. This has frequently resulted in different ratings for the same equipment under the same ambient and operating conditions in the same region. It is possible that two transmission owners with joint ownership of an interconnection line using their respective methodologies could derive two different line ratings, even with both applying the same assumptions in ambient and operating conditions.[102]

The standards for determining facility ratings do not establish a uniform or consistent set of methodologies; instead they only require Transmission Owners or Generation Owners to document its chosen methodology. The standards do not address Recommendation Number 27 of the Blackout Report that NERC "develop clear, unambiguous requirements for the calculation of transmission line ratings."[103]

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[102] This is true even when the different ratings are not due to the ratings of their respective terminal equipment.

[103] Blackout Report at 162 (Recommendation Number 27 states that "NERC should develop enforceable standards for transmission line ratings. NERC should develop clear, unambiguous requirements for the calculation of transmission line ratings (including dynamic ratings), and require that all lines of 115 kV or higher be rerated according to these requirements by June 30, 2005.").

C. Concerns Specific to Individual Standards

Facility Connection Requirements (FAC-001-0)

The purpose of this standard reads: "To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements."

No substantive issues were identified at this time.

Coordination of Plans for New Generation, Transmission, and End-User facilities (FAC-002-0)

The purpose of this standard reads: "To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements."

The FAC standards require system performance assessments in accordance with reliability standard TPL-001-0, which relates only to normal system conditions.[104] Staff notes that Order No. 2003[105] requires assessments of both normal and post-contingency conditions and is therefore more rigorous than FAC-002-0.

Transmission Vegetation Management Program (FAC-003-1)

The purpose of this standard reads:

> To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

Staff's technical concerns with this standard are discussed in section B.2 above.

With regard to Measures and Requirements, both the Requirement on reporting transmission outages and the Levels of Non-Compliance in the standard -- which are based on the number of tree contact outages -- represent good performance metrics to improve reliability.

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[104] Standard TPL-001-0

[105] Order No. 2003 at P 89 and 145.

The Measures and Levels of Non-Compliance have been significantly improved compared to those in the Version 0 standard. They appear to be adequate at this time.

Methodologies for Determining Electrical Facilities (FAC-004-0)

The purpose of this standard reads: "To ensure that electrical facilities used in the transmission and storage of electricity are rated in compliance with applicable Regional Reliability Organization requirements."[106]

Staff's concerns with this standard are discussed in section B.3 above.

Electrical Facility Ratings for System Modeling (FAC-005-0)

The purpose of this standard reads: "To ensure that electrical facilities used in the transmission and storage of electricity are rated in compliance with applicable Regional Reliability Organization requirements."

No substantive issues were identified at this time.

Facility Ratings Methodology (FAC-008-1)

The purpose of this standard reads: "To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies."

This standard was recently approved by the NERC Board of Trustees and will become effective on August 7, 2006, replacing standard FAC-004-0, Methodologies for Determining Electrical Facilities.

The concerns discussed in section B.3 above, regarding facility rating methodologies, are at issue in this standard. This standard does not provide a uniform or consistent set of methodologies; instead it only requires equipment owners to document the respective methodologies they use. Therefore, this standard does not appear to address Recommendation Number 27 of the Blackout Report to establish "clear, unambiguous requirements" for the calculation of transmission line ratings.[107]

Establish and Communicate Facility Ratings (FAC-009-1)

The purpose of this standard reads: "To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies."

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[106] According to NERC, this standard will be retired on August 7, 2006 when Standard FAC-008-1 comes into effect.

[107] Blackout Report at 162.

This standard requires Transmission Owners and Generator Owners to establish and communicate their facility ratings to other reliability and operating entities. This is a new standard effective October 7, 2006. Staff notes that there is no substantive issue with the standard at this time.

Transfer Capability Methodology (FAC-012-1)

The purpose of this standard reads: "To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies."

This standard requires the Reliability Coordinators and Planning Authority to document their methodologies in determining inter-regional and intra-regional transfer capabilities by stating that "Transfer Capabilities shall respect all applicable System Operating Limits (SOLs)." This is a new standard effective August 7, 2006.

Staff notes that entities in different regions have historically calculated transfer capabilities using different assumptions or approaches.[108] These approaches may be different between the Reliability Coordinators and Planning Authorities in a region, and may also vary from region to region. Therefore, the variable application of transfer capabilities is essentially a regional difference. A move toward standardization of the inter-regional and intra-regional transfer capability may be desirable to ensure an adequate level of reliability and minimize undue negative impact on competition. Staff notes that this issue is being considered in Docket Nos. RM05-17-000 and RM05-25-000.

Establish and Communicate Transfer Capability (FAC-013-1)

The purpose of this standard reads: "To ensure that Transfer Capabilities used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies."

This standard requires Reliability Coordinators and Planning Authority to establish the transfer capabilities and provide them to the reliability entities. This is a new standard effective October 7, 2006. Staff notes that there is no substantive issue with the standard at this time.

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[108] *See* NERC Long-Term AFC/ATC Task Force Final Report, revised April 14, 2005.

IX. INT: INTERCHANGE SCHEDULING AND COORDINATION

A. Description and General Issues

The Interchange Scheduling and Coordination (INT) group of reliability standards consists of four standards applicable Balancing Authorities, Purchasing-Selling Entities, Transmission Service Providers, Reliability Coordinators and Transmission Operators, but potentially also applicable to Load Serving Entities and Generator Operators.

This group of standards addresses the process of Interchange Transactions, which occur when electricity is purchased and transmitted from a seller to a buyer across the power grid.[109] Specific information must be identified in electronic labels, known as Tags, and these must accompany the transactions to allow a reliability assessment by the affected reliability and operating entities. In addition, communication, submission, assessment and approval of these Tags, including modifications, must be completed for reliability consideration before implementation of the transaction.

Generally, these standards raise issues in the areas of Applicability, Measures, Compliance, and Requirements. Further, these standards include instances of ambiguity. Set forth below is a discussion of primary issues and an evaluation of individual standards in light of these observations.

Of the four standards in this group, one of them has partial Measures and Levels of Non-Compliance provisions, one has partial Measures but no Levels of Non-Compliance provisions, and two have neither Measures nor Levels of Non-Compliance provisions. The two standards that contain Measures provisions do not provide specific compliance criteria to address all of the reliability goals identified in the purposes and all of the requirements contained in the INT group of standards. NERC has indicated that some of these standards will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Implementation of the Blackout Report recommendations regarding reliability involves standard INT-004 in this group. Below follows a discussion of primary issues evident in the INT standards as well as an evaluation of the individual standards in the context of these observations.

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[109] NERC Glossary at 8 (defines "Interchange Transaction" at page 8 as "[a]n agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries").

B. Primary Issues in the Interchange Scheduling and Coordination Standards

1. Use of Interchange Transaction Modifications to Address Actual System Operating Limit or Interconnection Reliability Operating Limit Violations

The standards allow modifications to be made to Interchange Transactions in order to address actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations.[110] Considering the specific requirements on Tag modification, submission, assessment, approvals and transaction implementation, the total time necessary to implement the Interchange Transactions modification is expected to exceed by a substantial amount the timeframe of 30 minutes that is established in other standards, *i.e.*, the requirement that the system be returned to a secure operating state from a SOL/IROL violation as soon as possible, but no later than 30 minutes after the violation. The standards currently do not contain a clear warning of this potential limitation and therefore could lead to the inappropriate use of transaction modification by reliability entities to deal with actual SOL/IROL violations. In doing so, valuable time would be lost that is needed to re-adjust the system effectively using other operational corrective actions.

C. Issues Specific to Individual Standards

Interchange Transaction Tagging (INT-001-0)

The purpose of this standard reads:

> To ensure that Interchange Transactions, certain Interchange Schedules, and intra-Balancing Authority Area transfers using Point-to-Point Transmission Service are Tagged in adequate time to allow the transactions to be assessed for reliability impacts by the affected Reliability Coordinators, Transmission Service Providers, and Balancing Authorities, and to allow adequate time for implementation.

This standard has only one Measure. It requires documentation to demonstrate that all scheduled interchanges are tagged. This is not sufficient to ensure that all requirements in the standard are met. In addition, the standard does not contain

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[110] *See* NERC Glossary at 8 (defining IROL as "[t]he value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages").

any Levels of Non-Compliance. Without Levels of Noncompliance, the ERO will not have norms that are specific enough to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Interchange Transaction Tag Communication and Reliability Assessment (INT-002-0)

The purpose of this standard reads:

> To ensure that Interchange Transaction information is provided to all entities needing to make reliability assessments and to ensure all affected reliability entities access the reliability impacts of Interchange Transactions before approving or denying a Tag. To communicate the approvals and denials of the Tag and the final composite status of the Tag.

Staff notes that Reliability Coordinators and Transmission Operators are not included in the applicability section of this standard. This is important because power flows for Interchange Transactions cross multiple Balancing Authority Areas and affect multiple transmission paths in an Interconnection, requiring the participation of Reliability Coordinators and Transmission Operators.

The standard contains no Compliance Measures or Levels of Non-Compliance. Without Compliance Measures and Levels of Noncompliance, the ERO will not have norms that are specific enough to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Interchange Transaction Implementation (INT-003-0)

The purpose of this standard reads:

> To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations. To Ensure Balancing Authorities incorporate all confirmed Schedules into their ACE equations.

The standard contains no Compliance Measures or Levels of Non-Compliance. Without Compliance Measures and Levels of Noncompliance, the ERO will not have norms that are specific enough to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Interchange Transaction Modifications (INT-004-0)

The purpose of this standard reads:

> To allow modifications to Interchange Transactions to address potential or actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations or other reliability conditions. To ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.

The standard contains requirements concerning Generator Operators and Load-Serving Entities, but they are not listed in the applicability section, which may have the effect of exempting them from the standard or at least complicating the task of applying the standard to them. For example Requirement R2 specifically states "[a] Generator Operator or Load Serving Entity may request the Host Balancing Authority to modify..." If these entities are not listed in the applicability sections, the enforceability of this provision is undermined.

The standard includes a provision to allow modifications to Interchange Transactions to address actual SOL/IROL violations. Staff's concerns are discussed in more detail in section B1 above.

The standard does not contain any Levels of Non-Compliance provisions. The one Measure contained in the standard is aimed at Requirement R5 which is applicable to Purchasing-Selling entities and Sink Balancing Authorities and not any of the other Requirements in the standard. Without Levels of Noncompliance and adequate Measures, the ERO will not have norms that are specific enough to implement consistent and effective enforcement. NERC has not identified this standard as one that would be modified and resubmitted for Commission approval in November 2006.

X. IRO: INTERCONNECTION RELIABILITY OPERATIONS AND COORDINATION

A. Description and General Issues

The Interconnection Reliability Operations and Coordination (IRO) standards focus on the responsibilities and authorities of Reliability Coordinators.[111] These reliability standards establish requirements for data, tools, and wide area view, which are intended to facilitate a Reliability Coordinator's ability to perform its responsibilities and ensure the reliable operation of the interconnected grid.

Generally, these standards raise issues in the areas of Measures, Compliance and Requirements. Further, these standards are subject to varying interpretations.

Three standards require entities to provide the data necessary to support reliability coordination tasks and implement operating instructions, as directed by Reliability Coordinators to preserve the reliability and integrity of the Bulk Electric System. However, the standards do not provide specific Requirements and Measures concerning wide area view and facilities. The second, third and fifth standards lack Measures and compliance Requirements. The sixth standard does not contain sufficient criteria or Measures to assess compliance with the Requirements.

If the IRO standards provided clear and objective criteria or Measures concerning all of the Requirements identified, they could be enforced in a consistent and non-preferential manner. NERC has indicated that some of these standards will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Implementation of the Blackout Report recommendations regarding reliability involves standards IRO-003 and IRO-006 in this group. Also, if left unresolved, the issue of conflicting definitions concerning the Bulk-Power System vs. the Bulk Electric System, discussed in the Common Issues chapter of this document, would add to interpretation and enforceability problems for the standards in this chapter.

The following is a discussion of the primary issues and an evaluation of individual reliability standards in light of these observations.

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[111] *See* NERC Glossary at 13 (defining Reliability Coordinator as "the entity with the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations…").

B. Primary Issues in Interconnection Reliability Operation and Coordination Standards

1. Unclear Responsibilities and Authorities of Reliability Coordinators

Some real-time operating actions that are carried out by operating entities, such as Transmission Operators and Balancing Authorities, may have a reliability impact on the footprint of their Reliability Coordinator and those of adjacent Reliability Coordinators. These operating entities must communicate their intended operating actions to their Reliability Coordinator who is responsible for assessing the overall interconnection reliability impact and authorizing the implementation of these operating actions. Unclear responsibilities and authorities of Reliability Coordinators may leave a gap in the communication, assessment and authorization process and may result in a significant adverse impact on the reliable operation of the interconnected grid. Currently, the standards do not explicitly assign responsibilities to Reliability Coordinators in the Purposes or Requirements. Assignment can only be inferred from the definition of Reliability Coordinator in the NERC Glossary.[112] The Blackout Report recommended that NERC develop clear roles, responsibilities, and authorities for Reliability Coordinators to ensure effective and timely action in critical situations.[113]

2. Operation Under Normal and Post-Contingency Conditions

In real-time, system operating conditions constantly change from one operating state to another to accommodate changes in demand, generation dispatches, interchange schedules, planned element outages, and system contingencies. The Interconnection Reliability Operating Limit (IROL) is the level above which the system may cascade if a critical contingency occurs. The standards state

> If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.[114]

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[112] NERC Glossary at 13.

[113] Blackout Report at 158.

[114] Standard IRO-005-1 (R3).

One interpretation of this Requirement allows an IROL to be exceeded during normal operation (prior to a contingency), provided that corrective actions are taken within 30 minutes. In this interpretation, if a single critical contingency[115] were to occur, it would result in instability, uncontrolled separation or perhaps cascading outages. A more conservative interpretation of this Requirement is that an IROL should only be exceeded after a contingency and the system must subsequently be returned to a secure condition as soon as possible, but in no longer than 30 minutes.

3. Specificity on Wide Area View

The NERC Glossary defines Wide Area as "[t]he entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits."[116] Wide Area visualization allows Reliability Coordinators to maintain situational awareness over neighboring areas.[117] Thus, Reliability Coordinators must be continuously aware of the status and loading of critical facilities in neighboring systems that could have an adverse impact on their own system. Inadequate reliability tools and backup capabilities contributed to a lack of situational awareness and played an integral role in causing the August 14, 2003 blackout.[118] The Blackout Report emphasizes that "[t]he need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations."[119] The Blackout Report recommends that NERC work with control areas and Reliability Coordinators to "[c]larify criteria for identification of operationally critical facilities, and improve dissemination of updated information on unplanned outages."[120] The IRO standards do not specify the criteria for identifying critical facilities whose operating status can affect the reliability of neighboring systems and, therefore, hampers effective Wide Area visualization.

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[115] The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

[116] NERC Glossary at 18.

[117] *Id.*

[118] *See* Blackout Report at 159.

[119] *Id.*

[120] *Id.* at 163.

4. Use of Transmission Loading Relief

Transmission Loading Relief (TLR) procedures are used to relieve overloads on transmission facilities by curtailing and adjusting transactions. The existing TLR procedures, with the exception of the last step invoking load shedding, are likely incapable of being implemented quickly enough to achieve the desired goal of relieving IROL violations in less than 30 minutes. In reviewing the control area and Reliability Coordinator transcripts from August 14, 2003, the Task Force concluded that the TLR process is "cumbersome, perhaps unnecessarily so, and not fast and predictable enough for use in situations in which an Operating Security Limit [SOL] is close to or actually being violated."[121] The Task Force also recommended that NERC "[c]larify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit [SOL]."[122] The current IRO standards allow the utilization of the TLR procedure to mitigate potential and actual SOL or IROL violations on any transmission facility. The IRO standards could potentially lead system operators to inappropriately use transmission loading relief procedures to mitigate actual IROL violations. In doing so, valuable time that could be utilized to re-adjust the system by other, more effective, operating measures would be lost.[123]

C. Concerns Specific to Individual Standards

Reliability Coordination – Responsibilities and Authorities (IRO-001-0)
The purpose of this standard reads:

> Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a Reliability Coordinator delegates tasks to others, the Reliability

[121] Blackout Report at 163 (Note - the NERC Glossary defines System Operating Limit (SOL) as 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.").

[122] Blackout Report at 163.

[123] For example, consider the findings of the Blackout Report as to why the blackout began. The Report, when considering the utilities' decision to use TLR to relieve overload, states "The only way that these high loadings could have been relieved would not have been from the redispatch that AEP requested [which is TLR], but rather from significant load-shedding by [First Energy] in the Cleveland area." Blackout Report at 63.

> Coordinator retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another.

This standard does not explicitly assign responsibilities to Reliability Coordinators in its Purpose or Requirements. Assignment can only be inferred from the definition of Reliability Coordinator in the NERC Glossary.[124] This issue is discussed in more detail in the Primary Issues section under the heading "Unclear Responsibilities and Authorities of Reliability Coordinators."

Reliability Coordination – Facilities (IRO-002-0)

The purpose of this standard reads: "Reliability Coordinators need information, tools and other capabilities to perform their responsibilities."

The standard does not have any Compliance Measures and Levels of Noncompliance and without such specificity, the ERO will not have norms that are specific enough to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Reliability Coordination – Wide Area View (IRO-003-0)

The purpose of this standard reads:

> The Reliability Coordinator must have a wide area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators.

The standard states as a Requirement that

> When a Reliability Coordinator is aware of an operational concern, such as declining voltages, excessive reactive flows, or an IROL violation, in a neighboring Reliability Coordinator Area, it shall contact the Reliability Coordinator in whose area the operational concern was observed. The two Reliability Coordinators shall coordinate any actions, including emergency assistance, required to mitigate the operational concern.[125]

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[124] NERC Glossary at 13.

[125] Standard IRO-003-0 R2.

This standard does not specify the criteria for defining critical facilities in adjacent systems whose status and loading conditions could affect the reliability of neighboring systems. An in-depth discussion of staff's concerns regarding this standard appears in the Primary Issues section of this chapter under the heading "Specificity on Wide Area View."

NERC's Version 1 IRO-003-1 standard was recently approved by the NERC Board of Trustees with an effective date of August 1, 2006. However, the revised reliability standard does not address the concern raised above.

Without Compliance Measures and Levels of Non-Compliance in either Version 0 or Version 1, the ERO will not have norms that are specific enough to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Reliability Coordination – Operations Planning (IRO-004-1)
The purpose of this standard reads:

> Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

Other standards require the system to be operated in a manner that allows it to be returned to a stable state as soon as possible but no longer than 30 minutes after a contingency occurs and to be able to withstand another contingency without cascading. However, this standard does not require that the system be assessed in the next-day planning analysis to identify the control actions needed to bring the system back to a stable state, with an effective implementation time of within 30 minutes, so that the system will be able to withstand the next contingency without cascading.

Reliability Coordination – Current Day Operations (IRO-005-1)
The purpose of this standard reads:

> The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the

> Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

This standard is ambiguous in that it allows different interpretations in respecting IROL limits under normal and contingency conditions as discussed in section B.2 above. This version of the standard was recently approved by the NERC Board of Trustees with an effective date of November 1, 2006.

Without Compliance Measures and Levels of Non-Compliance, the ERO will not have norms that are specific enough to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Reliability Coordination – Transmission Loading Relief (IRO-006-1)
The purpose of this standard reads:

> Regardless of the process it uses, the Reliability Coordinator must direct its Balancing Authorities and Transmission Operators to return the transmission system to within its Interconnection Reliability Operating Limits as soon as possible, but no longer than 30 minutes. The Reliability Coordinator needs to direct Balancing Authorities and Transmission Operators to execute actions such as reconfiguration, re-dispatch, or load shedding until relief requested by the TLR process is achieved.

Requirement R2 of this standard states that:

> A Reliability Coordinator experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area shall, at its discretion, select from either a "local" (Regional, Interregional, or subregional) transmission loading relief procedure or an Interconnection-wide procedure."[126]

This standard does not address the concerns expressed in the Blackout Report that call for "clarify[ing] that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit [SOL]."[127] While the intent of the standard as expressed in the Purpose statement is appropriate, Requirement R2 could lead reliability entities to deploy inappropriate operating measures, such as TLR procedures, to mitigate actual IROL violations. Staff's concerns

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[126] Standard IRO-006-1 (R2).

[127] Blackout Report, Recommendation Number 31 at 163.

regarding this standard are more fully addressed in the Primary Issues section of this chapter under the heading "Use of Transmission Loading Relief."

Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators (IRO-014-1)

The purpose of this standard reads:

> To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations."

No substantive issues were identified for this standard at this time.

Notifications and Information Exchange Between Reliability Coordinators (IRO-015-1)

The purpose of this standard reads:

> To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

No substantive issues were identified for this standard at this time.

Coordination of Real-time Activities Between Reliability Coordinators (IRO-016-1)

The purpose of this standard reads:

> To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

No substantive issues were identified for this standard at this time.

XI. MOD: MODELING, DATA, AND ANALYSIS

A. Description and General Issues

The Modeling, Data, and Analysis group of the current reliability standards consists of 23 standards aimed at RROs, Transmission Service Providers, Transmission Owners, Transmission Planners, Generation Owners, Resource Planners, Planning Authorities, and Load-Serving Entities.[128] The standards may be grouped into four distinct categories. The first category covers documentation, review, and validation of Total Transfer Capacity (TTC), Available Transfer Capacity (ATC), Capacity Benefit Margin (CBM), and Transmission Reliability Margin (TRM) calculations and is applicable to the RROs.[129] The second category covers steady-state and dynamics data and models and is applicable to Transmission Owners, Transmission Planners, Generation Owners, Resource Planners, and the RROs.[130] The third category covers actual and forecast demand data and is applicable to the RROs, Transmission Planners, Planning Authorities, Load-Serving Entities, and Resource Planners.[131] The fourth category covers the verification of generator real and reactive power capability and is applicable to the RROs and Generation Owners.[132]

In general, these standards raise issues with regard to the applicability and Requirements sections of the standard. In addition, multiple standards have the same stated purpose rather than having purpose statements tailored to the particular goal of each standard.

Of the 23 standards in this group, fourteen delegate responsibility to the RRO as the applicable entity for one or more Requirements to develop methodologies, procedures and grant variances. These standards have been referred to as "fill-in-the blank" standards. These regional methodologies and procedures have not been submitted to the Commission for approval or otherwise been subject to the requirements of section 215. The standards therefore pose problems of enforcement. In addition, the RRO is not currently defined as a user, owner, or operator of the Bulk-Power system.

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[128] Twenty-one of these Standards are Version 0 Standards, while two were recently approved by the NERC Board of Trustees as Version 1 Standards with an effective date of January 1, 2007.

[129] North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standards MOD-001-0 to MOD-009-0.

[130] Standards MOD-010-0 to MOD-015-0.

[131] Standards MOD-016-0 to MOD-021-0.

[132] Standards MOD-024-1 to MOD-025-1.

Implementation of the Blackout Report recommendations regarding reliability involves standards MOD-014 and MOD-015 in this group. Below follows a discussion of primary issues and an evaluation of individual standards in the context of these observations.

B. Primary Issues in the Modeling, Data, and Analysis Standards

1. Quality of System Modeling Data and Data Exchange Practices

Good data and system models are essential for accurately simulating the performance of the Bulk Electric System for use in planning, operations planning, real-time operations and after-the-fact analysis of disturbances. The Blackout Report states that "[t]he after-the-fact models developed to simulate August 14 conditions and events found that the dynamic modeling assumptions for generator and load power factors in regional planning and operating models were frequently inaccurate. In particular, the assumptions of load power factor were overly optimistic – loads were absorbing much more reactive power than the pre-August 14 models indicated."[133] To address this deficiency, Recommendation Number 24 of the Blackout Report states the need to "[i]mprove quality of system modeling data and data exchange practices."[134] In describing the work required, the Blackout Report states that "[p]ower flow and transient stability simulations should be periodically benchmarked with actual system events to validate model data."[135] While the standards require that steady state and dynamics data be submitted and that steady state and dynamic system models are prepared, there are no requirements to validate these models through periodic benchmarking and appropriately modify them against actual system events in accordance with Recommendation Number 24 of the Blackout Report.

2. Different Approaches to TTC, ATC, CBM, and TRM Methodologies

ATC is derived from TTC after allowing for existing transmission commitments including retail customer service and a Capacity Benefit Margin,[136] less a Transmission

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[133] Blackout Report at 160.

[134] *Id.*

[135] *Id.*

[136] Defined in NERC Glossary as "The amount of TTC preserved by the transmission provider for LSEs whose loads are located on that TSPs system, to enable access by the LSE to generation from the interconnected system to meet generation reliability requirements."

Reliability Margin.[137] The TTC and ATC values must satisfy certain principles that balance both technical and commercial issues. The standards leave the development of methodologies and the procedures for periodic review of TTC, ATC, CBM and TRM calculations to RROs. This has resulted in different interpretations and applications of calculation methodologies resulting in different values for ATC when using the same data and assumptions. As such, the different approaches could have an undue negative impact on competition. The Commission is considering this issue in Docket Nos. RM05-17-000 and RM05-25-000 and anticipates addressing it in any Notice of Proposed Rulemaking that may be issued in those dockets.

C. Concerns Specific to Individual Standards

1. Fill-in-the-Blank Standards

This group of nine standards has one or more Requirements for a RRO to develop methodologies and procedures or grant variances for use by users, owners and operators within the region. These standards have been referred to as "fill-in-the blank" standards. These regional methodologies and procedures have not been submitted to the Commission for approval or otherwise subject to the requirements of section 215. The standards therefore pose problems of enforcement. In addition, they may result in regional differences which may not be necessitated by either a physical difference of the Bulk-Power System or the application of a more stringent Reliability Standard. The regional differences could have an undue negative impact on competition. In addition, the RRO is not currently defined as a user, owner, or operator of the Bulk-Power system.

These standards are listed as follows:

Review of TTC and ATC Calculations and Results (MOD-002-0)
The purpose of this standard reads:

> To promote the consistent and uniform application of transfer capability calculations among Transmission System Providers, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC).

This standard requires that each RRO, in conjunction with its members, develop and implement a procedure to periodically review (at least annually) and ensure that the TTC

[137] Defined in NERC Glossary as "The amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure."

and ATC calculations and resulting values of member Transmission Service Providers comply with the Regional TTC and ATC methodology and applicable Regional criteria.

Procedure for Input on TTC and ATC Methodologies and Values (MOD-003-0)
The purpose of this standard reads:

> To promote the consistent and uniform application of Transfer Capability calculations among Transmission System Providers, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC).

The standard requires that each RRO, in conjunction with its members, develop and document a procedure that transmission users can use to communicate their concerns or questions regarding the TTC and ATC methodology and values of the Transmission Service Provider(s), and how these concerns or questions will be addressed.

Regional Steady-State Data Requirements and Reporting Procedures (MOD-011-0)
The purpose of this standard reads: "To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems."

The standard requires RROs within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections.

Planning Authorities are not included in the Requirements section of this standard. They are the entities responsible for coordination and integration of transmission facilities and Resource plans, as well as one of the entities responsible for the integrity and consistency of the data.

Regional Reliability Organization Dynamics Data Requirements and Reporting Procedures (MOD-013-0)
The purpose of this standard reads: "To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems."

The standard requires the RRO, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections.

Planning Authorities are not included in the Requirements section of this standard. They are the entities responsible for coordination and integration of transmission facilities and Resource plans, as well as one of the entities responsible for the integrity and consistency of the data.

Development of Interconnection-Specific Steady State System Models (MOD-014-0)

The purpose of this standard reads: "To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems."

The standard requires that RRO(s) within each Interconnection to coordinate and jointly develop and maintain a library of solved (converged) Interconnection specific steady-state system models.

While the standard requires the development of steady state models, it does not require periodic verification or appropriate modification of models against field data in accordance with Recommendation Number 24 of the Blackout Report.[138]

Development of Interconnection-Specific Dynamics System Models (MOD-015-0)

The purpose of this standard reads: "To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems."

The standard requires the RRO(s) within each Interconnection to coordinate and jointly develop and maintain a library of initialized (with no Faults or system Disturbances) Interconnection-specific dynamics system models linked to the steady-state system models, as appropriate in accordance with Standard MOD-014(R1).

While the standard requires the development of dynamic models, it does not require periodic verification or appropriate modification of models against field data in accordance with Recommendation Number 24 of the Blackout Report.[139]

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[138] Blackout Report at 160.

[139] Blackout Report at 160.

Actual and Forecast Demands, Net Energy for Load, Controllable DSM (MOD-016-0)

The purpose of this standard reads:

> To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management (DSM) programs is needed.

The standard requires that the Planning Authority and RRO have documentation identifying the scope and details of the actual and forecast (a) Demand data, (b) Net Energy for Load data, and (c) controllable DSM data to be reported for system modeling and reliability analyses.

Staff notes that the Transmission Planner, which is one of the entities involved in assuring the integrity and consistency of the load, energy, and DSM data, is not included in the applicability.

Verification of Generator Gross and Net Real Power Capability (MOD-024-1)

The purpose of this standard reads: "To ensure accurate information on generator gross and net Real Power capability is available for steady state models used to assess Bulk Electric System reliability."

The standard requires the RRO to establish and maintain procedures to address verification of generator gross and net Real Power capability.

Staff notes that the standard does not require definition of the test conditions, *e.g.*, ambient temperature, river water temperature, etc., or methodologies for calculating de-rating factors for other conditions, such as higher ambient temperatures than the test temperature.

Verification of Generator Gross and Net Reactive Power Capability (MOD-025-1)

The purpose of this standard reads: "To ensure accurate information on generator gross and net Reactive Power capability is available for steady state models used to assess Bulk Electric System reliability."

The standard requires RROs to establish and maintain procedures to address verification of generator gross and net Reactive Power capability.

2. Absence of Consistent Methodology for Calculating ATC

Five of this group of seven standards have requirements that delegate the development of methodologies and procedures for TTC/ATC/CBM/TRM to the RROs. These five standards have been referred to as "fill-in-the-blank" standards. The remaining two standards delegate the Transmission Service Providers to document their procedures for the use of CBM and report the use of CBM by Load Serving Entities. Such delegation from all seven standards may result in unnecessary regional variations not justified by technical differences and inconsistent application.

Documentation of TTC and ATC Calculation Methodologies (MOD-001-0)
The purpose of this standard reads:

> To promote the consistent and uniform application of Transfer Capability calculations among users, the Regional Reliability Organization shall develop methodologies for calculating Total Transfer Capacity (TTC) and Available Transfer Capacity (ATC) that comply with NERC definitions for TTC and ATC, NERC Reliability Standards, and applicable Regional criteria.

The standard requires that each RRO, in conjunction with its members, develop and document a Regional TTC and ATC methodology. This standard has been referred to as a "fill-in-the-blank" standard.

Staff notes that the RROs have historically calculated TTC/ATC using different approaches.

Documentation of Regional CBM Methodologies (MOD-004-0)
The purpose of this standard reads: "To promote the consistent and uniform application of transmission Transfer Capability margins calculations, Capacity Benefit Margin (CBM) must be calculated in a consistent manner."

The standard requires each RRO, in conjunction with its members, to develop and document a Regional CBM methodology. This standard has been referred to as a "fill-in-the-blank" standard.

The standard does not specify how CBM is determined and allocated across transmission paths. Further, the standard does not address the effect of associated transmission service requirements and curtailment provisions on transmission customers.

The standard does not specify the criteria to be used in determining the inclusion or exclusion of generation resources, reserves and loads described in four of its Requirements (R1.5, R1.6, R1.9 and R1.10).

Procedure for Verifying CBM Values (MOD-005-0)

The purpose of this standard reads:

> To promote the consistent and uniform application of Transfer Capability calculations among transmission system users, the Regional Reliability Organizations need to review adherence to Regional methodologies for calculating Capacity Benefit Margin (CBM).

The standard requires each RRO, in conjunction with its members, to develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers to ensure that they comply with the RRO's CBM methodology. It does not, however, actually require there to be a consistent and uniform calculation of CBM. This standard has been referred to as a "fill-in-the-blank" standard.

Procedure for the Use of CBM Values (MOD-006-0)

The purpose of this standard reads: "To promote the consistent and uniform application of transmission Transfer Capability margins calculations among transmission system users."

The standard requires each Transmission Service Provider to document its procedure on the use of Capacity Benefit Margin values, but not to implement a consistent and uniform calculation of CBM.

Documentation of the Use of CBM (MOD-007-0)

The purpose of this standard reads:

> To promote the consistent and uniform application of Transfer Capability margin calculations among transmission system users by developing methodologies for calculating Capacity Benefit Margin (CBM). This methodology shall comply with NERC definitions for CBM, the NERC Reliability Standards, and applicable Regional criteria.

The standard requires each Transmission Service Provider (TSP) to report the use of CBM by the Load-Serving Entities (LSEs) to the Region, NERC and the transmission users.

The standard does not specify how CBM should be reserved to allow both Transmission Providers and Transmission Customers to meet their respective generation reliability criteria.

Documentation and Content of Each Regional TRM Methodology (MOD-008-0)

The purpose of this standard reads:

> To promote the consistent application of transmission Transfer Capability margin calculations among Transmission Service Providers and Transmission Owners, each Regional Organization shall develop a methodology for calculating Transmission Reliability Margin (TRM). This methodology shall comply with the NERC definition for TRM, the NERC Reliability Standards, and applicable Regional criteria.

The standard requires each RRO, in conjunction with its members, to develop and document a Regional TRM methodology. This standard has been referred to as a "fill-in-the-blank" standard. The standard does not specify how TRM is determined and allocated across transmission paths.

Requirement R1.5 requires the description of the formal process for the RRO to grant variances from the Regional TRM methodology. The standard does not specify the criteria for granting variances.

Procedure for Verifying TRM Values (MOD-009-0)
The purpose of this standard reads: "To promote the consistent application of transmission Transfer Capability margin calculations among Transmission System Providers and Transmission Owners."

The standard requires each RRO, in conjunction with its members, to develop and implement a procedure to review Transmission Reliability Margin (TRM) calculations and resulting values of member Transmission Service Providers. This provision is to ensure that the Transmission Service Providers comply with the Regional TRM methodology, and are periodically updated and available to transmission users. This standard has been referred to as a "fill-in-the-blank" standard.

3. Omission of the Planning Authority as an Applicable entity

This group of two standards, which covers data requirements for steady state and dynamic simulations, does not include the Planning Authority as an applicable entity. They are the entities responsible for coordination and integration of transmission facilities and Resource plans, as well as one of the entities responsible for the integrity and consistency of the data.

These standards are listed as follows:

Steady-State Data for Transmission System Modeling and Simulation (MOD-010-0)
The purpose of this standard reads: "To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems."

The standard requires the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners to provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Standard MOD-011-0(R1).

Dynamics Data for Transmission System Modeling and Simulation (MOD-012-0)
The purpose of this standard reads: "To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems."

The standard requires the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners to provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined by Standard MOD-013-0(R4).

4. Accuracy and Bias of Load Forecasts

This group of five standards addresses actual data, forecast data, and demand management. The standards do not require a consistent methodology in validating and forecasting demand Specifically, there are no requirements to report the accuracy, error and bias of load forecasts. Staff notes that several standards in this group address separate matters but have identical purpose statements. Generally, staff suggests such statements be augmented or tailored to reflect the specific aspect of the purpose the given standard is designed to achieve. These standards are listed as follows:

Aggregated Actual and Forecast Demands and Net Energy for Load (MOD-017-0)
The purpose of this standard reads:

> To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessment to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

The standard requires the Load-Serving Entity, Planning Authority and Resource Planner to each annually provide demand in MW and energy in GWh reported by hour, month and year. Each of these needs to be aggregated by Regional, sub-regional, Power Pool, and individual system or Load-Serving Entity bases to NERC, the RROs and others as specified in Standard MOD-016-0(R1).

Reports of Actual and Forecast Demand Data (MOD-018-0)

The purpose of this standard reads:

> To ensure that Assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

The standard requires Load-Serving Entities, Planning Authorities, Transmission Planners, and Resource Planners to indicate whether the demand data of nonmember entities within an area or Region are included and to address assumptions, methods, and the manner in which uncertainties are treated.

Forecasts of Interruptible Demands and DCLM Data (MOD-019-0)

The purpose of this standard reads:

> To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcements for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

The standard requires Load-Serving Entities, Planning Authorities, and Transmission Planners to annually provide forecasts of interruptible demand and Direct Control Load Management (DCLM) to NERC, the RROs and other entities as specified in Standard MOD-016(R1).

Providing Interruptible Demands and DCLM Data (MOD-020-0)

The purpose of this standard reads:

> To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

The standard requires Load-Serving Entities, Planning Authorities, Transmission Planners, and Resource Planners to each make known its amount of interruptible demand

and Direct Control Load Management (DLCM) to Transmission Operators, Balancing Authorities, and Reliability Coordinators on request within 30 days.

Accounting Methodology for Effects of Controllable DSM in Forecasts (MOD-021-0)

The purpose of this standard reads:

> To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management (DSM) programs is needed.

The standard requires Load Serving Entities, Planning Authorities, Transmission Planners, and Resource Planners to document how they address DSM impacts in their forecasts for peak demand and energy requirements.

XII. PER: PERSONNEL PERFORMANCE, TRAINING AND QUALIFICATIONS

A. Description and General Issues

The four Personnel Performance, Training and Qualifications (PER) standards apply to Transmission Operators, Reliability Coordinators, and Balancing Authorities. These reliability standards include such topics as operating personnel responsibility and authority, operating personnel training, operating personnel credentials, and reliability coordination staffing.

Staff's concerns about the PER standards generally relate to Measures, Compliance, Requirements, and susceptibility to multiple interpretations.

Of the four reliability standards in this group, one does not contain criteria or measures to assess compliance with the Requirements or ascertain the Levels of Non-Compliance required for enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

In its review, staff identified three PER standards that contain technical issues either because they may be incomplete or lack specificity and therefore might not adequately protect the reliable operation of the Bulk-Power System. Some of the standards fail to address the knowledge gained from past operating incidents. Other reliability standards are ambiguous regarding the requirements for compliance. In addition, the applicability of two of the reliability standards appears to be too narrow in scope.

Also, if left unresolved, the issue of conflicting definitions concerning the Bulk-Power System vs. the Bulk Electric System, discussed in the Common Issues Chapter of this document, would add to interpretation and enforceability problems for the standards in this chapter.

Implementation of the Blackout Report recommendations regarding reliability involves standards PER-002 through PER-004 in this group. The following is a discussion of the primary issues and an evaluation of individual reliability standards in light of these observations.

B. Primary Issues in the Personnel Performance, Training and Qualifications Reliability Standards

1. Scope of Applicability

The Personnel Performance, Training and Qualifications reliability standards require each Transmission Operator and Balancing Authority to have training programs for all of their operating personnel who occupy positions that either have the primary responsibility, directly or through communication with others, for real-time operation of the interconnected Bulk Electric System or who are directly responsible for complying with the NERC reliability standards. However, Transmission Operators and Balancing Authorities are not the only entities that have operating personnel who, directly or indirectly, have the capacity to impact the reliable operation of the Bulk-Power System or who are directly responsible for complying with the reliability standards. Reliability Coordinators, Generator Operators, Operations Planning, and Operations Support staff also potentially impact the reliable operation of the Bulk-Power System yet these entities are not required by the existing standards to participate in a mandatory training program consistent with their roles, responsibilities, authorities and tasks.

2. Training Program Objectives

The Blackout Report reviewed several previous major North American outages and concluded that inadequate operator training was a contributory factor that the August 14, 2003 Blackout had in common with earlier major outages.[140] The Blackout Report identified training-related recommendations made in studies of major outages:

- Thorough programs and schedules for operator training and retraining should be vigorously administered.
- A full-scale simulator should be made available to provide operator training personnel with "hands-on" experience in dealing with possible emergency or other system conditions.
- Procedures and training programs for system operators should include anticipation, recognition, and definition of emergency situations.[141]

Inadequate Operator training has contributed to several of the past major system disturbances.[142] In the Blackout Report, the Task Force stated that some Reliability

[140] Blackout Report at 107.

[141] *Id.* at 110

Coordinators and Control Area Operators did not receive adequate training in recognizing and responding to system emergencies.[143] In fact, the "deficiency in training contributed to the lack of situational awareness and failure to declare an emergency on August 14 while operator intervention was still possible (before events began to occur at a speed beyond human control)."[144] According to the Blackout Report, the improvement of near-term and long-term training and certification requirements for operators, reliability coordinators and operator support staff will aid in the proper recognition and adequate response to emergencies.[145] The Task Force suggested that NERC require training for the planning staff at control areas and Reliability Coordinators concerning power system characteristics and load, VAr, and voltage limits to enable them to develop rules for operating staff to follow.[146] In addition, the Task Force urged NERC to "require control areas and reliability coordinators to train grid operators, IT support personnel and their supervisors to recognize and respond to abnormal automation system activity."[147] Further, NERC was advised by the Task Force to "commission an advisory report by an independent panel to address a wide range of issues concerning reliability training programs and certification requirements."[148] The existing NERC standards do not address these conclusions identified in the Blackout Report.

The PER standards do not require training programs tailored to the needs of the respective functions with differing authorities, responsibilities, roles and tasks. The standards require that each Transmission Operator and Balancing Authority provide a training program for all specified operating personnel to ensure their operating proficiency.[149] While this standard sets out broad objectives that a training program must satisfy, it does not specify the minimum expectations of a training program or the minimum number of hours of training (other than a requirement of five days per year for realistic simulation training) consistent with the roles, responsibilities and authorities of operating and support personnel. Therefore, the nature, objective, and criteria of operator

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[142] *Id* at 107.

[143] *Id.* at 157.

[144] *Id.*

[145] *Id.*, Recommendation Number 19 at 156 ("The task force supports [these] near-term requirements *strongly.*") (emphasis added).

[146] *Id.*, Recommendation Number 19A at 156.

[147] *Id.*, Recommendation Number 19B at 157.

[148] *Id.*, Recommendation Number 19C at 157.

[149] *See* North American Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Operating Personnel Training, Standard PER-002-0 (R3.3) (effective Apr. 1, 2005).

training programs and minimum hours of training are open to interpretation. This lack of specificity allows programs to vary widely with each Transmission Operator or Balancing Authority and still comply with the PER standards.

Staff notes that EPAct 2005 contains a provision for training guidelines for non-nuclear electric energy industry personnel.[150] The training guidelines outlined in EPAct 2005 apply to workers engaged in the construction, operation, inspection or maintenance of non-nuclear electric generation, transmission or distribution systems and include, among others, requirements for competency, initial certification, assessment, and re-certification.[151]

Additionally, staff notes that there is a widely-accepted Systematic Approach to Training (SAT) methodology that has been successfully used in the electric industry as well as other industries.[152] SAT is credited with ensuring that training is conducted efficiently, effectively and directly related to the needs of the position in question.[153] Staff notes that the training program specifics in the standard might be greatly enhanced by considering some of the objectives and elements of the widely-accepted SAT concept.

3. Operating Personnel Certification

These standards require each Transmission Operator, Balancing Authority and Reliability Coordinator to staff all operating positions that have a primary responsibility for real-time operations or are directly responsible for complying with the reliability standards with NERC-certified staff. Generator Operators, who have responsibility for the real-time operation of the Bulk Electric System and are directly responsible for complying with NERC reliability standards, are not similarly required to be NERC-certified. Moreover, these standards do not specify the competencies operating personnel must demonstrate to

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[150] EPAct 2005, Pub. L. No. 109-58, § 1103(a), 119 Stat. 594 (providing for the development of personnel training guidelines by the Department of Labor in consultation with DOE, to support the reliability and safety of the electric system).

[151] *Id.* at § 1103(b)(1).

[152] 10 C.F.R. 50.120(b) (2006) (For example, the SAT approach is required by the Nuclear Regulatory Commission for Nuclear Power Plant Operator training).

[153] SAT objectives include: Management and Administration of Training and Qualification Programs; Development and Qualification of Training Staff; Trainee Entry-level Requirements; Determination of Training Program Content; Design and Development of Training Programs; Conduct of Training; Trainee Examinations and Evaluations; Training Program Evaluation. U.S. Department of Energy, Guidelines for Evaluation of Nuclear Facility Training Programs. Department of Energy, Standard 1070-94 Appendix (effective June 1994).

meet the certification requirements. NERC's System Operator Certification Program Manual outlines the requirements for certification, but the manual is not part of the standard and therefore is not enforceable.[154]

C. Concerns Specific to Individual Reliability Standards

Operating Personnel Responsibility and Authority (PER-001-0)

The purpose of this standard reads: "Transmission Operators and Balancing Authority operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System."

There are no substantive issues identified with this standard at this time.

Operating Personnel Training (PER-002-0)

The purpose of this standard reads: "Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation."

Reliability Coordinators, Generator Operators, Operations Planning and Operations Support staff are not included in this training requirement.

This standard does not specify minimum training programs, nor does it tailor training programs according to the needs of Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Operation Planning and support personnel with differing authorities, responsibilities, roles and tasks. Further discussion is provided above in section B.2 entitled, "Training Program Objectives."

Operating Personnel Credentials (PER-003-0)

The purpose of this standard reads: "Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System."

While the reliability standards require positions that have primary responsibility for real-time operation of the interconnected Bulk Electric System or positions that are directly responsible for complying with the NERC reliability standards to be filled with NERC-certified staff, the standards do not specify minimum certification requirements. NERC's System Operator Certification Program Manual outlines the requirements for

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[154] *See NERC's Application for Certification as the Electric Reliability Organization, Rules of Procedure of the Electric Reliability Organization, System Operator Certification Program Manual,* Appendix 6 *available at* ftp://www.nerc.com/pub/sys/all_updl/ero/application/ERO-Application-Complete.pdf.

certification.[155] However, the manual is not part of the standard and, thus the standard lacks an enforceable requirement in regard to system operator certification. Staff's concerns regarding this standard are further addressed under the section of this chapter entitled "Operating Personnel Certification."

Reliability Coordination – Staffing (PER-004-0)

The purpose of this standard reads: "Reliability Coordinators must have sufficient, competent staff to perform Reliability Coordinator functions."

Most of this standard addresses training issues, yet there is no requirement for a formal training program for Reliability Coordinators that is similar to the program required for Transmission Operators under standard PER-002-0.

Without Compliance Measures and Levels of Non-compliance, the ERO will not have benchmarks to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

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[155] *North American Electric Reliability Council's Application for Certification as the Electric Reliability Organization, Rules of Procedure of the Electric Reliability Organization, System Operator Certification Program Manual*, Appendix 6 *available at* ftp://www.nerc.com/pub/sys/all_updl/ero/application/ERO-Application-Complete.pdf.

XIII. PRC: PROTECTION AND CONTROL

A. Description and General Issues

Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operations. Protection systems are designed to detect faults and isolate the faulted elements from the system, thereby limiting the severity and propagation of system disturbances and preventing possible damage to protected elements. System Operating Limits and Interconnection Reliability Operating Limits are only valid when they recognize the protection system functionalities, settings and limitations. From the blackout on November 9, 1965 to the August 14, 2003 Blackout, one of the common factors among the major outages was the lack of coordination of system protection.[156]

Generally, these standards raise Measures, Compliance, and Requirements issues. The PRC standards consist of sixteen Version 0 standards and six Version 1 standards that apply to Transmission Operators, Transmission Owners, Generator Operators, Distribution Providers and RROs.[157] They cover a wide range of topics related to the protection and control of power systems.[158] However, NERC has recognized that these standards do not form a complete set of Protection and Control standards to meet the goal of reliability. The NERC Planning Standards state in relevant part:

> Certain planning standards that were a part of the Phase III- IV NERC compliance program were not included in the Version 0 reliability standards...[t]hese standards are important, nonetheless, as they contain critical reliability requirements in support of recommendations from the NERC and U.S./Canada Power System Outage Task Force reports on the August 14, 2003 Blackout...the NERC board resolved on October 15, 2004, that: "A satisfactory resolution of the issues regarding Phases III and IV of the planning standards would be to: (1) develop reliability standards covering the Phase III and Phase IV issues separate from the Version 0

[156] Blackout Report at 107.

[157] Three of the six Version 1 standards are intended to replace their Version 0 equivalents with effective dates of May 1, 2006 for PRC-003-1; August 1, 2006 for PRC-004-1; and May 1, 2006 for PRC-005-1.

[158] Topics addressed under the PRC standards include: system protection coordination, disturbance monitoring, under-frequency load shedding (UFLS), special protection systems, under-voltage load shedding (UVLS) and their assessments, database, event and mis-operation analysis, maintenance and testing requirements, and performance evaluation.

> effort, using the NERC standards development process; (2) have the Planning Committee expeditiously complete the drafting of the proposed standards needed to address the Phase III and Phase IV issues..." The SAR [Standards Authorization Request] propose[d] the development of reliability standards that address[ed] the disturbance monitoring and reporting requirements of those Phase III- IV planning standards.[159]

Implementation of the Blackout Report recommendations regarding reliability involves standards PRC-002, PRC-006, and PRC-020 through PRC-022 in this group. Also, if left unresolved, the issue of conflicting definitions concerning the Bulk-Power System vs. the Bulk Electric System, discussed in the Common Issues Chapter of this document, would add to interpretation and enforceability problems for the standards in this chapter. The following is a discussion of the primary issues and an evaluation of individual PRC standards in light of these observations.

B. Primary Issues in the Protection and Control Standards

1. Ambiguous Requirements for Protection Failures

The failure of a protection system has the potential to result in major outages or cascading. If a non-redundant protection system for a critical element fails and no corrective action is taken, the system could be subject to the risk of cascading if a critical contingency subsequently occurred. The PRC standards require that where a protective relay or equipment failure reduces system reliability, Transmission Operators or Generator Operators shall take corrective action *as soon as possible*.[160] However, the PRC standards do not designate a limit to the time period for corrective actions.[161] This is inconsistent with the requirement that System Operators initiate actions or emergency procedures to re-adjust the system as soon as possible and *no later than 30 minutes* after a contingency to minimize reliability risks under the IRO and TOP standards.

[159] *See* NERC Planning Standards Phase III-IV, *available at* http://www.nerc.com/~filez/standards/Phase-III-IV.html.

[160] Standard PRC-001-0 (R2.1-2) (emphasis added).

[161] Corrective actions may include removing system elements, operating to a lower limit that does not impact reliability, etc.

2. Integrated and Coordinated Approach to Bulk-Power System Protection

Under-frequency load shedding (UFLS) and under-voltage load shedding (UVLS) are protection systems designed to detect abnormal conditions in the system and assist in preventing possible cascading by shedding load automatically at specific locations and for specified abnormal conditions. UFLS and UVLS act as a safety net for the grid. Generation protection systems disconnect the generator to prevent damage to the generator. Line protection systems are designed to sense faults in the lines and, where detected, take the faulty line out of service. An integrated and coordinated approach between UFLS, UVLS, line protection and generation protection is needed to "ensure that at the local and regional level these interactive components provide an appropriate balance of risks and benefits in terms of protecting specific assets and facilitating overall grid survival."[162]

In assessing protection measures, the Task Force recommended that NERC "[m]ake more effective and wider use of system protection measures."[163] In particular, the Task Force urged NERC to "determine the goals and principles needed to establish an integrated approach to relay protection for generators and transmission lines and the use of under-frequency and under-voltage load shedding (UFLS and UVLS) programs."[164] Currently, the PRC standards are not specific enough to be interpreted as requiring an integrated and coordinated approach to achieving the above goals and principles.

3. Criteria for Maintenance and Testing of Protection Systems

Protection systems must be maintained and tested at regular intervals to ensure that they will operate as intended when called upon. Maintenance intervals vary depending on the type and nature of the protection systems, as well as the reliability impact of a potential failure of those systems. These standards do not specify the criteria to determine the appropriate maintenance intervals, nor do the standards specify maximum allowable maintenance intervals for the protection systems. As the standards do not designate a maximum maintenance interval based on the protection systems, the lack of such a requirement could result in the potential ineffective operation of a protection system when called upon. This is in contrast with standard PRC-006-0, which requires periodic assessments of the effectiveness of regional UFLS programs at least once every five

[162] Blackout Report at 159.

[163] Blackout Report, Recommendation Number 21 at 158.

[164] Blackout Report at 159.

years regardless of the circumstance - a good example of a maximum allowable interval without specific justification.

C. Concerns Specific to Individual Reliability Standards

1. Individually Identified Standards

The following group of standards contains issues unique to each standard and are individually discussed below.

System Protection Coordination (PRC-001-0)
The purpose of this standard reads: "To ensure system protection is coordinated among operating entities."

This standard does not define the maximum time period for corrective actions if a protective relay or equipment failure reduces system reliability. This is inconsistent with the requirement that System Operators re-adjust the system within 30 minutes for contingencies as required under the IRO and TOP standards. These concerns are discussed in more detail in section B1 above.

Without Compliance Measures and Levels of Noncompliance, the ERO will not have benchmarks to implement consistent and effective enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Development and Documentation of Regional UFLS Programs (PRC-006-0)
The purpose of this standard reads: "Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program."

This standard applies to RROs. However, RROs have not been classified as a user, owner, or operator of the Bulk-Power System. The standard has been referred to as a "fill-in-the-blank" standard.

This standard is not specific enough to address Blackout Report Recommendation Number 21 concerning an integrated and coordinated approach. The discussion of "Under-Frequency Load Shedding and Under-Voltage Load Shedding Coordination with Generation and Line Protection Systems" in section B.2 of this chapter details concerns regarding this standard.

There is a Requirement to perform periodic assessments of the effectiveness of the regional UFLS programs and design details at least once every five years – a good example of a maximum allowable interval without specific justification. However, the standard does not contain a Requirement for an integrated and coordinated approach among UFLS, line protection, generation protection and generator under-frequency protection as suggested by Blackout Report Recommendation Number 21.

UFLS Performance Following an Underfrequency Event (PRC-009-0)

The purpose of this standard reads: "Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program."

Standard PRC-009-0 also requires that the "Transmission Owner, Transmission Operator, Load-Serving entity and Distribution Provider that owns or operates a UFLS program ... shall analyze and document its UFLS program performance in accordance with its Regional Reliability Organization's UFLS program."[165] In addition, the standard requires the same entities to "provide documentation of the analysis of the UFLS program to its Regional Reliability Organization and NERC on request 90 calendar days after the system event."[166] Staff notes that there is no similar reporting requirement for operation events of under-voltage load shedding.

Assessment of the Design and Effectiveness of UVLS Program (PRC-010-0)

The purpose of this standard reads: "Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Under Voltage Load Shedding (UVLS) program."

The discussion of "Integrated and Coordinated Approach to Bulk-Power System Protection" in section B.2 of this chapter highlights staff's concerns regarding this standard in detail.

Special Protection System Assessment (PRC-014-0)

The purpose of this standard reads: "To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected."

The maximum allowable interval of at least once every five years as a Requirement for assessing the effectiveness of the special protection systems is a good example of a maximum allowable interval without specific justification.

[165] Standard PRC-009-0 (R1).

[166] *Id.* at R2.

This standard applies to RROs. However, RROs have not been classified as a user, owner, or operator of the Bulk-Power System. The standard has been referred to as a "fill-in-the-blank" standard.

2. Specifications of Maintenance Intervals

This group of four standards does not specify the criteria to determine the appropriate maintenance intervals or maximum allowable intervals for protection systems to ensure effectiveness. Specific concerns are explained in the previous section, entitled, "Criteria for Maintenance and Testing of Protection Systems" of the primary issues identified in this chapter. Beyond this concern, there are no substantive issues identified at this time for the following standards.

Transmission Protection System Maintenance and Testing (PRC-005-0)
The purpose of this standard reads: "To ensure all transmission protection system misoperations are analyzed for cause and corrective action, and maintenance and testing programs are developed and implemented."

The revised standard PRC-005-1 was recently approved by the NERC Board of Trustees with an effective date of May 1, 2006. The title of the standard has been changed to include generation protection. Also, the purpose properly reflects the title and intent of the standard. However, standard PRC-005-1 does not address the concern regarding maintenance intervals discussed above.

Underfrequency Load Shedding Equipment Maintenance Programs (PRC-008-0)
The purpose of this standard reads: "Provide last resort system preservation measures by implementing an Under Frequency Load Shedding (UFLS) program."

Undervoltage Load Shedding System Maintenance and Testing (PRC-011-0)
The purpose of this standard reads: "Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Under Voltage Load Shedding (UVLS) program."

Special Protection System Maintenance and Testing (PRC-017-0)
The purpose of this standard reads: "To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected."

3. RROs Designated as the Sole Applicable Entity

This group of five standards designates RROs as the applicable entity. Staff is concerned about the appropriateness of RROs serving as the applicable entity in the new mandatory Standards structure. These standards have been referred to as "fill-in-the-blank" standards. This concern is discussed in the Common Issues chapter of this assessment. Beyond this concern, there are no substantive issues identified at this time for the following standards.

Define and Document Disturbance Monitoring Equipment Requirements (PRC-002-0)

The purpose of this standard reads: "To ensure that Disturbance monitoring equipment is installed in a uniform manner to facilitate development of models and analyses of events."

Regional Procedure for Transmission Protection System Misoperations (PRC-003-1)

The purpose of this standard reads: "To ensure that all transmission protection system misoperations [must be] analyzed for cause and corrective action and maintenance and testing programs are developed and implemented."

Special Protection System Review Procedure (PRC-012-0)

The purpose of this standard reads: "To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected."

Special Protection System Database (PRC-013-0)

The purpose of this standard reads: "To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems."

Under-Voltage Load Shedding Program Database (PRC-020-1)

The purpose of this standard reads: "To ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the Risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES."

This Version 1 standard was recently approved by the NERC Board of Trustees with an effective date of August 1, 2006, though it understandably still does not address the applicability concerns.

4. No Substantive Issues Identified

No substantive issues have been identified at this time for these six PRC standards.

Analysis and Reporting of Transmission Protection System Misoperations (PRC-004-0)
The purpose of this standard reads: "To ensure all transmission protection system misoperations are analyzed for cause and corrective action and maintenance and testing programs are developed and implemented."

PRC-004-1 was recently approved by the NERC Board of Trustees with an effective date of August 1, 2006. No substantive issues for the Version 0 or Version 1 standard were identified at this time.

Assuring Consistency with Regional UFLS Program Requirements (PRC-007-0)
The purpose of this standard reads: "Provide last resort System preservation measures by implementing an Under Frequency Load Shedding (UFLS) program."

Special Protection System Data and Documentation (PRC-015-0)
The purpose of this standard reads:

> To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

Special Protection System Misoperations (PRC-016-0)
The purpose of this standard reads:

> To ensure that all Special Protection Systems (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

Under-Voltage Load Shedding Program Data (PRC-021-1)
The purpose of this standard reads: "Ensure that data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES)."

This Version 1 standard was recently approved by the NERC Board of Trustees with an effective date of August 1, 2006.

Under-Voltage Load Shedding Program Performance (PRC-022-1)

The purpose of this standard reads: "Ensure that Under-Voltage Load Shedding (UVLS) programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES)."

This Version 1 standard was recently approved by the NERC Board of Trustees with an effective date of May 1, 2006.

XIV. TOP: TRANSMISSION OPERATIONS

A. Description and General Issues

The Transmission Operations (TOP) group of reliability standards consists of eight standards aimed at Transmission Operators, Generator Operators and Balancing Authorities. They cover responsibilities and decision-making authority for reliable operations, requirements for operations planning, planned outage coordination, real-time operations, provision of operating data, monitoring of system conditions, reporting of operating limit violations and actions to mitigate such violations. Complementary standards for Reliability Coordinators are covered under the Interconnection Reliability Operations and Coordination (IRO) group of standards in chapter X of this assessment.

In general, these standards raise issues in the areas of Measures, Compliance, and Requirements.

Of the eight standards in this group, five do not contain criteria or measures to assess compliance with the Requirements. These five standards lack Levels of Non-compliance that are needed for enforcement of penalties. The Levels of Non-compliance in one standard are based on procedural rather than substantive requirements regarding the quality, completeness and timeliness of the information submitted. NERC has indicated that these standards will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

An examination of the Requirements has identified five standards that have significant technical issues because they may be incomplete and therefore might not adequately protect the reliable operation of the Bulk-Power System. They do not address the lessons learned from past operating incidents; might not contain a technically sound means to achieve the specified reliability goal; or may not be clear and unambiguous regarding compliance requirements. In addition, the reliability goal of one of the standards may be too narrow in scope to adequately protect Bulk-Power System reliability.

Implementation of the Blackout Report recommendations regarding reliability involves standard TOP-006 in this group. Also, if left unresolved, the issue of conflicting definitions concerning the Bulk-Power System, discussed in the Common Issues Chapter of this document, would add to interpretation and enforceability problems for the standards in this chapter.

Below follows a discussion of primary issues and an evaluation of individual standards in the context of these observations.

B. Primary Issues in the Transmission Operations Standards

1. Ability to Readjust the System Following a Contingency

The standards require that plans be developed to meet dynamic changes to the system in the operations planning time frame, such as scheduled and unscheduled changes in system configuration, demand patterns, generation dispatch and interchange schedules. The unscheduled changes to system configuration and generation dispatch are referred to as a single contingency (defined as the loss a transmission circuit, generator, single DC pole, or transformer). However, following a single contingency, Standard IRO-005-1 requires that the system be adjusted to compensate for the contingency as soon as possible but no later than 30 minutes after the contingency. This Requirement is to ensure that the system is returned to a secure operating state so it can withstand the next contingency without causing instability, uncontrolled separation or cascading outages.

This group of standards does not, however, require that the system be assessed to the same extent in the day ahead planning analysis, nor does it require identification of control actions, implementable within 30 minutes, that are needed to bring the system back to a stable state in order to withstand the next contingency without cascading. This may present a potential vulnerability as operators may not be aware of available control actions or worse may not have control actions, other than firm load shedding, available to them to adjust the system to a stable state after it incurs its first contingency. This can lead to poor execution and reliability risk after the first contingency has occurred in real-time operations.

2. Operation Under Normal Pre-Contingency Conditions

The primary reliability goal of the Transmission Operations standards is to ensure that instability, uncontrolled separation or cascading outages will not occur as a result of the most severe single contingency. However, these standards are worded ambiguously enough to be interpreted in two very different ways. A conservative interpretation is that under normal system conditions, *i.e.*, before any contingency occurs, the system must be operated within Interconnection Reliability Operating Limits (IROL). A less strict interpretation of these standards is that operation above IROLs under normal pre-contingency conditions is permitted provided the system is returned to a secure operating state as soon as possible but not later than 30 minutes after the IROLs were exceeded. In the case of the latter interpretation, during the period when IROL is exceeded even a single system contingency (such as the loss of transmission circuit, transformer, generator, or single DC pole) could cause instability, uncontrolled separation, and even a cascading blackout.

3. Minimum Acceptable Tools to Aid Situational Awareness

The Blackout Report states that "a principal cause of the blackout was a lack of situational awareness, which was in turn a result of inadequate reliability tools and backup capabilities."[167] To address this deficiency, Recommendation Number 22 of the Blackout Report requires that NERC evaluate and adopt better real-time tools for operators and Reliability Coordinators so they can recognize and respond to system emergencies in a timely manner.[168] While the NERC standards identify the data requirements, they do not identify any minimum acceptable tools and capabilities to turn the data into information necessary to understand critical reliability functions, and therefore the standards lack an important Requirement in this area.

C. Concerns Specific to Individual Standards

Reliability Responsibilities and Authorities (TOP-001-0)
The purpose of this standard reads: "To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency."

The standard does not contain any Measures to assess compliance with the Requirements or any Levels of Non-Compliance required for enforcement of penalties. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Normal Operations Planning (TOP-002-0)
The purpose of this standard reads: "Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events."

Staff notes that this standard specifies that capacity and energy reserves to local areas must be deliverable. Other standards require the system be operated in a manner that allows it to be returned to a stable state within 30 minutes after a contingency occurs and to be able to withstand another contingency without cascading. However, this standard does not require that the system be assessed in the next day planning analysis to identify control actions, which can be implemented in 30 minutes, that are needed to bring the system back to a stable state and can withstand the next contingency without cascading. Staff's concerns in this area are discussed in more detail in section B1 above.

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[167] Blackout Report at 159.

[168] *See id.*

The reference to "single contingency" is defined as the loss of a transformer, transmission circuit, single DC pole, or generator, but does not include the assessment of outages of multiple elements as a result of a single component failure.[169] This might leave a potential gap in the analysis of and planning for contingencies, as the loss of a single relay, breaker, control system component, transmission tower, etc., can affect multiple system elements.

The standard recognizes the need to communicate changes in generator "real and reactive capability as well as the status of automatic voltage regulators."[170] However, the standard does not include a requirement to communicate a change in the status of equally important Power System Stabilizers. These stabilizers are critical components for stability performance.

The standard does not contain any Measures to assess compliance with the Requirements or Levels of Non-Compliance required for enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Planned Outage Coordination (TOP-003-0)

The purpose of this standard reads:

> Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

The standard requires outage information on transmission lines and transformers greater than 100 kV. These Requirements – which do not include a requirement for setting threshold levels – are inconsistent with the stated purpose, as they assume that only systems greater than 100 kV or generators above 50 MW will affect the reliability of interconnected operations. Although this may be true in most instances, either justification should be provided for the threshold of 100 kV for transmission and 50 MW for generation outages on a case-by-case basis, or else the standard could be expanded to cover all facilities that have an impact on reliability. The loss of less than 100 kV transmission lines or transformers and less than 50 MW generator units may affect

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[169] Failure of an electrical component includes relay and control system failures, which may remove more than one element.

[170] North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standard TOP-002-0(R14).

system stability in load pockets or remote sections of the grid depending upon system conditions.

While standard TOP-002-0 requires coordination of planned outages on a current-day, next day and seasonal basis for normal operations planning, this standard only requires next day reporting for planned outages and does not include longer range planning. This gap may affect the reliability of the system because proper assessment of the system and coordination between generation and transmission outages may not occur. This lack of information may also have an impact on TTC/ATC calculations. The Levels of Non-Compliance are based on having a process in place for providing information, but they do not contain requirements for actually providing the information.

Transmission Operations (TOP-004-0)

The purpose of this standard reads: "To ensure that the transmission system is operated so that instability, uncontrolled separation or cascading outages will not occur as a result of the most severe single Contingency or specified multiple Contingencies."

Staff notes that an assessment on a regional basis of the potential impact of multiple outages in day-ahead operations planning is included in the Requirements. However, the conditions under which multiple outages can occur are undefined in the Regional Differences section. Only those Requirements that are included in the accepted standards are enforceable.

The standard requires the operation of the system within IROL and SOL. When the system enters an unknown state (*i.e.*, any state for which operating limits have not been determined), Requirement R4 of Standard TOP-004-0 requires the operator to "restore operations to respect proven reliable power system limits within 30 minutes."[171] The phrase "within 30 minutes" could be interpreted as a grace period. However, such an interpretation may not be consistent with the intent that while 30 minutes is deemed a reasonable time period, it is expected that actions will be taken as soon as possible and without delay.

The standard does not contain any Measures to assess compliance with Requirements or Levels of Non-Compliance required for enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

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[171] Standard TOP-004-0 (R4).

Operational Reliability Information (TOP-005-1)

The purpose of this standard reads: "To ensure reliability entities have the operating data needed to monitor system conditions within their areas."

Attachment 1 of TOP-005-1, entitled "Electric System Reliability Data," specifies the data required but it does not include the operational status of Special Protection Systems and Power System Stabilizers. The absence of this information can lead to erroneous assessments of system capability that can in turn expose the system to unreliability risk.

Monitoring System Conditions (TOP-006-0)

The purpose of this standard reads: "To ensure critical reliability parameters are monitored in real-time."

However, while the requirements identify the data to be gathered, they fail to describe the tools necessary to turn that data into critical reliability parameters, *e.g.*, system capability or contingency analysis, which are required to achieve situational awareness. Reliability Coordinators, Transmission Operators, and Balancing Authorities must be aware of the status of their respective systems, and such situational awareness can not be obtained by viewing massive amounts of raw data.

The standard does not contain any Measures to assess compliance with Requirements or Levels of Non-Compliance required for enforcement. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

Reporting SOL and IROL Violations (TOP-007-0)

The purpose of this standard reads: "This standard ensures that SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed."

Requirement R2 states "Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes."[172] However, the use of the words "other events" in Requirement R2 opens it up to interpretation. One interpretation is that it allows IROLs to be exceeded under normal pre-contingency conditions, provided the system can be returned to a secure state within 30 minutes. A more conservative interpretation is that the Requirement does not allow IROLs to be exceeded under normal pre-contingency conditions, and that after a contingency occurs the system must be returned to a secure condition as soon as possible and no later than 30 minutes. (This

[172] Standard TOP-007-0.

issue was explained in more detail under the section entitled "Primary Issues in the Transmission Operations Standards" in item B.2 above.)

Response to Transmission Limit Violations (TOP-008-0)

The purpose of this standard reads: "To ensure Transmission Operators take action to mitigate SOL and IROL violations."

The standard does not contain any Measures to assess compliance with Requirements or any Levels of Non-Compliance required for enforcement of penalties. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

XV. TPL: TRANSMISSION PLANNING CHAPTER

A. Description and General Issues

The Transmission Planning (TPL) group of reliability standards consists of six standards aimed at Transmission Planners, Planning Authorities and RROs. Four of the standards address the types of system simulations and assessments that must be performed to ensure that reliable systems are developed to meet present and future system needs.[173] Two standards relate to information required to assess Regional compliance with planning criteria and for self-assessment of the reliability of the region.[174]

In general, these standards raise issues of the following types: Requirements that are ambiguous, limited sets of contingencies, and Requirements or lack of Requirements that may have an undue negative impact on competition.

All six TPL standards contain a list of Measures to assess compliance with the Transmission Planning standards and Levels of Non-Compliance required for enforcement. Two of the standards are solely applicable to the RROs -- entities that currently are not identified as a user, owner or operator of the Bulk-Power System. Four standards have technical issues because they may either be incomplete, vague or subject to different interpretations.

In addition, if left unresolved, the issue of conflicting definitions concerning the Bulk-Power System vs. the Bulk Electric System, discussed in the Common Issues Chapter of this document, would add to interpretation and enforceability problems for the standards in this chapter. Staff notes that several standards in this group address separate matters but have identical purpose statements. Generally, staff suggests such statements be augmented or tailored to reflect the specific aspect of the purpose the given standard is designed to achieve.

Set forth below is a discussion of primary issues and an evaluation of individual standards in light of these observations.

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[173] North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standards TPL-001-0, TPL-002-0, TPL-003-0, TPL-004-0.

[174] Standards TPL-005-0, TPL-006-0.

B. Primary Issues in the Transmission Planning Standards

1. Stressing the System during Simulations

In carrying out power systems simulations to determine the need for system upgrades or reinforcements with sufficient lead time to implement, it is important to ensure that the system under study is sufficiently stressed so that any underlying weaknesses or deficiencies can be identified. It is equally important to test the performance of the system under study for a wide variety of probable scenarios. Such scenarios would typically simulate a range of generation dispatches including generator outages, a range of demand levels and load power factors, a range of transactions and a range of transmission outages including reactive power devices.[175] Such simulations would determine the most onerous set of system conditions, which might not be peak demand conditions. In addition, these tests would identify requirements for generators that must run to remove local transmission constraints,[176] or alternatively identify the inability to deliver generation to load due to insufficient transmission capacity. These are especially important for the near term (one to five years), as the results would be instructive to seasonal, monthly, weekly and day-ahead operations planning studies and as both aspects are critical to reliable operations in real time. Adherence to applicable reliability criteria for the overall set of simulations provides a good indication of the ability of the system to remain reliable for a variety of operating conditions.

The standards require entities to "cover critical system conditions and study years,"[177] but they do not require that sensitivity studies be carried out, nor do they specify the rationale for determining critical system conditions and study years. System conditions are as important as contingencies in evaluating the performance of present and future systems.[178]

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[175] Some Regions use the term "deliverability" to describe part of this process.

[176] These are referred to as Reliability Must Run or RMR units.

[177] Requirement R1.3 of Standards TPL-001, TPL-002, TPL-003, TPL-004. Critical study years are those years determined by simulations to require transmission upgrades or reinforcement to meet reliability criteria.

[178] Expected changes in system conditions may be short-term predictive maintenance outages or longer-term corrective maintenance outages. The length of a corrective maintenance outage may be dependent upon the number and types of spare equipment that an entity has available. Widespread weather events may also impact system conditions.

2. Element-Based vs. Event-Based Contingencies

The Planning Standards require demonstration through valid assessments that the system is planned so that it can be operated to supply projected customer demands and firm Transmission Services at all demand levels under a set of contingencies as defined in Table 1 (Transmission System Standards – Normal and Emergency Conditions) of the TPL Standards. Table 1 is a key part of the Planning Standards and lays out the system performance requirements for a range of contingencies grouped according to the number of elements forced out of service as a result of the contingency. For example: Category A applies to the normal system with no contingencies; Category B applies to contingencies resulting in the loss of a single element defined as a generator, transmission circuit, transformer, single DC pole with or without a fault; Category C applies to a contingency resulting in loss of two or more elements, such as any two circuits on a multiple tower line or both poles of a bi-polar DC line; while Category D applies to extreme contingencies resulting in loss of multiple elements, such as a substation or all lines on a right-of-way. The system performance expectations for Category C contingencies are lower than those for Category B contingencies, in that they allow unspecified amounts of planned or controlled loss of demand.

The term "Reliable Operation" as set forth in section 215(a)(4) of the FPA is defined as:

> Reliable Operation means operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of sudden disturbance, including a Cybersecurity Incident, or unanticipated failure of system elements.

Staff interprets this to mean that any element in the actual Bulk-Power System may fail and contingencies used in simulations should be consistent with what can occur in real-time operations based on the actual details of the Bulk-Power System.

The single unanticipated failure of some elements in the Bulk-Power System can result in the loss of multiple elements. Because of the resulting impact on reliability, some Regions[179] base their groupings according to the event irrespective of the number of elements forced out of service instead of categorizing contingencies according to elements forced out of service. For such a region, a single event that results in the loss of multiple elements, *e.g.*, a relay failure, that forces a DC bi-pole out of service or a lightening strike that simultaneously forces out of service both circuits of a double circuit

[179] *See, e.g.*, NPCC criteria A1 Document.

tower line, are grouped alongside those events which would result in loss of single elements such as a generator, transmission circuit or transformer. Through this variation in criteria, what is acceptable in one Region may not be acceptable in another Region because of historical adoption of reliability criteria and practices rather than physical differences in their systems.

3. Interpretation of Performance Requirements

As stated above, Table 1 of the Planning Standards lays out the system performance requirements for a range of contingencies. There are a number of footnotes associated with Table 1 meant to aid in the interpretation of the performance requirements. For example, the Requirements in Category B are no load loss or curtailment of firm transfers from contingencies resulting in the loss of a single element. But footnote (b) appended to these Requirements states in part "[p]lanned or controlled interruption of electrical supply to radial customers or some local Network customers, connected to or supplied by the faulted element or affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems."[180] This footnote is sufficiently ambiguous to allow differing interpretations. One interpretation of this statement is that load interruption for a single contingency is permitted, while another interpretation is that the practice is the exception rather than the rule, and for this reason load interruptions are not permitted for a single contingency except in very special circumstances where such interruption is limited to the firm load directly associated with the failure. In the case of the former interpretation, applicable entities may argue that they can deliberately interrupt firm load customers as a result of the loss of a single contingency without violating any reliability standards.

Other footnotes are also ambiguous and as such detract from the intent of the performance requirements stated in Table 1. They should be clarified so that they are applied appropriately and consistently by all the entities to whom they apply.

4. Assessment of Extreme Events

Extreme events are low probability but high impact events. Examples provided by NERC in the standards include loss of a substation, loss of all generating units at a station, loss of all transmission lines on a right-of-way, etc. Extreme events must be assessed to evaluate their risks and consequences. While the standards require such assessments, documentation of the results and submission to the RRO, they do not require that consideration be given either to reducing the probability of the loss of

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[180] Standard TPL-002, Table 1 Category B Footnote (b).

multiple elements or mitigating the impact. Furthermore, the standards do not explicitly require that the results of these assessments be shared with impacted entities or communicated to operations planning staff and control room operators.

Staff notes that a number of high-risk weather events, such as the hurricanes that impacted the Southern United States and an ice storm that impacted Canada, resulted in a greater impact on the Bulk-Power System in terms of the number of elements lost than the scenarios identified in the standards.

5. Scope of Elements for which the Reliability Standards Apply

The differences between the definition of Bulk-Power System in section 215 of the FPA and the definition of Bulk Electric System found in the NERC Glossary upon which the NERC standards rely, create a problematic discrepancy that could create reliability gaps. These gaps could allow for some interconnected electric energy transmission networks, and electric energy from generating facilities needed to maintain transmission system reliability to be outside of the mandatory Standards.

Clearly, this discrepancy in definitions, if left unaddressed, could interfere with maintaining reliability consistently across the Regions on an ongoing operations basis. The concern in this chapter is that the discrepancy is magnified when applied to contingencies that must be evaluated as part of the transmission planning process.

The current Planning Standards apply to all elements that constitute the Bulk Electric System. The NERC Glossary defines the Bulk Electric System as follows:

> As defined by the Regional Reliability Organization, the electrical generation of resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

According to this definition, each RRO may designate the scope of facilities to be included in, or excluded from, the system. Conflicting multiple definitions could result, which would in turn subject different facilities to the requirements of the standards or, alternatively, exclude various facilities from the standards.

Further, section 215(a)(1) defines Bulk-Power System as:

> Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system

> reliability. The term does not include facilities used in the local distribution of electric energy.[181]

The FPA and NERC definitions obviously differ. The standards currently are applied only to the Bulk Electric System as defined by each Region. However, section 215(a)(3) of the FPA defines Reliability Standard as a requirement approved by the Commission to provide for reliable operation of the Bulk-Power System. The term Bulk Electric System does not appear to include all the system components from all non-distribution voltage levels, control systems, and electric energy from all generating facilities needed to maintain transmission system reliability included in the definition of Bulk-Power System. Therefore, the definitions of Bulk Electric System and Bulk-Power System are very different with respect to the facilities to which the TPL standards would apply. The Bulk Electric System definition may not include all the elements and all the voltage levels implied in the definition of Bulk-Power System.

C. Concerns Specific to Individual Standards

System Performance Under Normal (No Contingency) Conditions (Category A) (TPL-001-0)

The purpose of this standard reads:

> System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

The standard's Requirements include a simulation and assessment of the ability of the Bulk Electric System to deliver firm demand and firm transactions with all elements in service for loads up to forecasted demand without violating performance requirements of Table 1 of the transmission planning standards. If an assessment indicates that a violation of the performance requirements has occurred, a plan to mitigate the violation is required.

The standard does not require the consideration of planned outages. Further, footnote (a) -- which states in part that "Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain

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[181] 18 C.F.R. § 39.1 (2005).

system control"[182] -- should be clarified that it is only applicable to Categories B, C, and D.

Further details are provided in the Primary Issues section above.

System Performance Following Loss of a Single BES Element (TPL–002–0)
The purpose of this standard reads:

> System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

The standard's Requirements include a simulation and assessment of the ability of the Bulk Electric System to deliver firm demand and firm transactions after the loss of a single element identified in Category B in Table 1 or a reduced set of those contingencies if accepted by the applicable RRO. If the assessment indicates a violation of the criteria has occurred, a plan to mitigate the violation is required.

Further details are provided in the Primary Issues section, items B.1, B.2 and B.3, above.

The NERC Transmission Issues Subcommittee (TIS) reviewed regional practices used for system design, planning and analysis. The TIS set forth its recommendations in a report.[183] Staff notes that the recommendations on clarifying the TPL standards contained in Appendix B of the NERC TIS Report have not been addressed.

System Performance Following Loss of Two or More BES Elements (TPL-003-0)
The purpose of this standard reads:

> System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

The standard's Requirements include a simulation and assessment of the ability of the Bulk Electric System to deliver firm demand and firm transactions after the loss of two or

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[182] Standard TPL-001-0 Table 1 Footnote (a).

[183] *See* NERC Transmission Issues Subcommittee, Evaluation of Criteria, Methods, and Practices Used for System Design, Planning and Analysis in Response to NERC Blackout Recommendation 13c (Nov. 28, 2005) (NERC TIS Report).

more elements identified in Category C in Table 1. If the assessment indicates a violation of the criteria has occurred, a plan to mitigate the violation is required.

Further details are provided in the discussion in the Primary Issues section, items B.1, B.2 and B.3, above.

Staff also notes that the recommendations on clarifying the TPL standards contained in Appendix B of the NERC TIS Report on regional practices referred to above have not been addressed.

System Performance Following Extreme BES Events (TPL-004-0)

The purpose of this standard reads:

> System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

The standard's Requirements include a simulation and assessment of the ability of the Bulk Electric System to deliver firm demand and firm transactions after the loss of multiple elements due to extreme events identified in Category D in Table 1.

The standard does not require that consideration be given either to reducing the probability of the loss of multiple elements or mitigating the impact of such outages. It also does not require that the results of these assessments be shared with impacted entities or communicated to operations planning staff and control room operators. This standard does not address scenarios that are equal to or more severe than actual weather events such as the hurricanes that impacted the Southern United States and an ice storm that impacted Canada.

Further details are provided in the Primary Issues section above.

Staff also notes that the recommendations on clarifying the TPL standards contained in Appendix B of the NERC TIS Report on regional practices referred to above have not been addressed.

Regional and Interregional Self-Assessment Reliability Reports (TPL-005-0)

The purpose of this standard reads:

> To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

The standard's Requirements are intended to provide NERC with the authority to collect RRO reliability self-assessments on a seasonal and next ten year basis. NERC uses this data to publish seasonal and long-term reliability assessments of the Bulk Electric System.

Staff finds no significant issues with this standard at this time and notes that these reports have been useful in understanding the performance of the present and future interconnected transmission system. It is expected that additional reports will be developed by the ERO in the future.

Assessment Data from Regional Reliability Organizations (TPL-006-0)

The purpose of this standard reads:

> To ensure that each Regional Reliability Organization complies with planning criteria, for assessing the overall reliability (Adequacy and Security) of the interconnected Bulk Electric Systems, both existing and as planned.

The standard's Requirements are intended to provide NERC with authority to collect specific RRO data, reports and system performance information on a seasonal and next ten year basis. NERC uses this data to publish seasonal and long-term reliability data of the Bulk Electric System.

Staff finds no significant issues with this standard at this time and notes that the data in these reports have been useful in understanding the trends in the performance of the interconnected transmission system.

XVI. VAR: VOLTAGE AND REACTIVE

A. Description and General Issues

The single Voltage and Reactive Control (VAR) reliability standard applies to Transmission Operators, Generator Operators and Purchasing-Selling Entities. The purpose of this standard reads:

> To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

Voltage control and reactive power supply are integral parts of reliable power system operations. A major imbalance between reactive power consumption and supply will lead to voltage collapse and cascading power outages. This has been a common causal factor in major power outages worldwide.[184]

In general, the VAR standard raises issues concerning the sufficiency of measures required, the lack of compliance directives, and ambiguities in interpreting the technical Requirements. Without Compliance Measures and Levels of Non-Compliance, the ERO will not have benchmarks to implement consistent and effective enforcement. This standard also does not contain sufficient Levels of Non-Compliance to assure the equitable enforcement of penalties. NERC has indicated that this standard will be modified to address this deficiency and resubmitted for Commission approval in November 2006.

An examination of the standard's Requirements has identified technical issues: the Requirements may be incomplete and therefore might not adequately protect the reliable operation of the Bulk-Power System, and they might not address the lessons learned from past operating incidents. Further, the Requirements are ambiguous regarding what is required to comply with the standard. In addition, implementation of the Blackout Report recommendations regarding reliability involves this standard.

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[184] Principles for Efficient and Reliable Reactive Power Supply and Consumption, Staff Report, Docket No. AD05-1-000 at p. 20 (February 4, 2005). *See also* Blackout Report at 18 (The August 14, 2003 Blackout was due in part to inadequate voltage control and reactive power supply, as stated: "insufficient reactive power was an issue in the blackout, but it was not a cause in itself. Rather, deficiencies in corporate policies, lack of adherence to industry policies, and inadequate management of reactive power and voltage caused the blackout, rather than the lack of reactive power.").

B. Primary Issues with the Voltage and Reactive Control Standard

1. Unclear and Incomplete Requirements

The VAR standard requires a Transmission Owner to "acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions,"[185] and "maintain system and Interconnection voltages within established limits."[186] These requirements may not assure reliable operation of power systems when operating under conditions that make them vulnerable to voltage collapse. Under heavy system loading conditions, and depending on system characteristics, operating voltages at levels that are traditionally considered normal (*e.g.*, 95 percent nominal) may no longer be stable operating voltages. Voltage magnitudes alone are poor indicators of voltage stability.[187]

The VAR standard does not address these pre- and post-contingency operating voltages, nor does it require Transmission Operators to maintain voltage levels above the voltage collapse points (*i.e.*, voltage instability) with a sufficient margin in accordance with good utility practice. For example, the Western Electric Coordinating Council's Reliability Criteria document, which contains a standard on voltage support and reactive power, states:

> For transfer paths, post-transient voltage stability is required with the path modeled at a minimum of 105% of the path rating (or Operational Transfer Capability) for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the path modeled at a minimum of 102.5% of the path rating (or Operational Transfer Capability).[188]

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[185] North American Electric Reliability Council, *Reliability Standards for the Bulk Electric Systems of North America*, Standard VAR-001-0 (Standard VAR-001-0) (R2).

[186] *Id.* at R6.

[187] Blackout Report at 36. *See also* Western Electric Coordinating Council, Reliability Criteria at 35 (April 2005) ("Voltage magnitudes alone are poor indicators of voltage stability or security because the system may be near collapse even if voltages are near normal depending on the system characteristics. The system must be planned so that there is sufficient margin between normal operating point and the collapse point to allow for reliable system operation.").

[188] WECC Reliability Criteria document at 32.

The above criteria state explicitly the voltage stability requirement and the margin requirements between the actual operating limits and the test levels in simulations for different contingencies. Staff notes that margins in Operational Transfer Capability are substitutable for voltage margins and either application is effective in ensuring reliability.

The VAR standard does not contain a Requirement that operations planning studies be carried out to identify the minimum permissible pre-contingency voltage levels and reactive power reserves. Requiring such studies would assure stable post-contingency voltage levels to avoid voltage collapse. These studies would also identify feasible corrective operating actions, which may include load shedding in pre-contingency conditions to avoid voltage collapse that may occur either in the pre- or post-contingency conditions. The standard does not currently require that these corrective operating actions be communicated to system operators as part of the day-ahead operations plan. In addition, the standard does not require similar voltage stability assessments to be carried out periodically during real-time operations so that system operators can continuously respond to changing system conditions.

The current standard does not address Recommendation Number 23 of the Blackout Report, which is to "[s]trengthen reactive power and voltage control practices in all NERC regions."[189] Staff notes that NERC, in response to this recommendation, established the Transmission Issues Subcommittee (TIS), which completed an evaluation of reactive power planning.[190]

2. Applicability

Voltage and reactive control is an integral part of Interconnection Reliability Operating Limits (IROLs). Voltage collapse can result in a widespread cascading outage on an Interconnection. Therefore, reliable operations of the Bulk-Power System require that Reliability Coordinators be authorized to direct and coordinate voltage and reactive control among operating entities in an Interconnection and assure that they can fulfill their role as the entity with the "highest level of authority."[191]

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[189] Blackout Report at 160.

[190] NERC Transportation Issues Subcommittee, Evaluation of Reactive Power Planning and Voltage Control Practices in Response to NERC Blackout Recommendation 7a (May 3, 2005).

[191] NERC Glossary (A Reliability Coordinator is defined as "The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of

(continued)

Staff notes that Requirement R3, which requires that "[e]ach Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider,"[192] is not currently applicable to Load-Serving Entities who are responsible for significantly more load on the system than the Purchasing-Selling Entities. The applicability of the standard is currently limited to Transmission Operators, Generator Operators and Purchasing-Selling Entities. This standard does not apply to Reliability Coordinators and Load-Serving Entities.

Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.").

[192] Standard VAR-001-0, Requirement R3.

APPENDIX A: STANDARDS REVIEWED

In this preliminary assessment, staff evaluated the same standards as those NERC submitted in its *Petition for Approval of Reliability Standards* dated April 4, 2006.

Standard Number	Title	Effective Date
BAL-001-0	Real Power Balancing Control Performance	04/01/05
BAL-002-0	Disturbance Control Performance	04/01/05
BAL-003-0	Frequency Response and Bias	04/01/05
BAL-004-0	Time Error Correction	04/01/05
BAL-005-0	Automatic Generation Control	04/01/05
BAL-006-0	Inadvertent Interchange	04/01/05
UA-1200	Urgent Action Standard - Cyber Security	08/13/03
CIP-001-0	Sabotage Reporting	04/01/05
COM-001-0	Telecommunications	04/01/05
COM-002-1	Communications and Coordination	11/01/06
EOP-001-0	Emergency Operations Planning	04/01/05
EOP-002-1	Capacity and Energy Emergencies	11/01/06
EOP-003-0	Load Shedding Plans	04/01/05
EOP-004-0	Disturbance Reporting	04/01/05
EOP-005-0	System Restoration Plans	04/01/05
EOP-006-0	Reliability Coordination - System Restoration	04/01/05
EOP-007-0	Establish, Maintain, and Document a Regional Blackstart Capability Plan	04/01/05
EOP-008-0	Plans for Loss of Control Center Functionality	04/01/05
EOP-009-0	Documentation of Blackstart Generating Unit Test Results	04/01/05
FAC-001-0	Facility Connection Requirements	04/01/05
FAC-002-0	Coordination of Plans for New Facilities	04/01/05
FAC-003-1	Vegetation Management Program	04/07/06
FAC-004-0	Methodologies for Determining Electrical Facility Ratings	04/01/05
FAC-005-0	Electrical Facility Ratings for System Modeling	04/01/05
FAC-008-1	Facility Ratings Methodology	08/07/06
FAC-009-1	Establish and Communicate Facility Ratings	10/07/06
FAC-012-1	Transfer Capabilities Methodology	08/07/06
FAC-013-1	Establish and Communicate Transfer Capabilities	10/07/06
INT-001-0	Interchange Transaction Tagging	04/01/05
INT-002-0	Interchange Transaction Tag Communication and Assessment	04/01/05
INT-003-0	Interchange Transaction Implementation	04/01/05
INT-004-0	Interchange Transaction Modifications	04/01/05

IRO-001-0	Reliability Coordination – Responsibilities and Authorities	04/01/05
IRO-002-0	Reliability Coordination – Facilities	04/01/05
IRO-003-1	Reliability Coordination – Wide Area View	08/01/06
IRO-004-1	Reliability Coordination - Operations Planning	11/01/06
IRO-005-1	Reliability Coordination – Current Day Operations	11/01/06
IRO-006-1	Reliability Coordination – Transmission Loading Relief	08/08/05
IRO-014-1	Procedures to Support Coordination Between Reliability Coordinators	11/01/06
IRO-015-1	Notifications and Information Exchange Between Reliability Coordinators	11/01/06
IRO-016-1	Coordination of Real-time Activities Between Reliability Coordinators	11/01/06
MOD-001-0	Documentation of TTC and ATC Calculation Methodologies	04/01/05
MOD-002-0	Review of TTC and ATC Calculations and Results	04/01/05
MOD-003-0	Procedure for Input on TTC and ATC Methodologies and Values	04/01/05
MOD-004-0	Documentation of Regional CBM Methodologies	04/01/05
MOD-005-0	Procedure for Verifying CBM Values	04/01/05
MOD-006-0	Procedures for Use of CBM Values	04/01/05
MOD-007-0	Documentation of the Use of CBM	04/01/05
MOD-008-0	Documentation and Content of Each Regional TRM Methodology	04/01/05
MOD-009-0	Procedure for Verifying TRM Values	04/01/05
MOD-010-0	Steady-State Data for Transmission System Modeling and Simulation	04/01/05
MOD-011-0	Regional Steady-State Data Requirements and Reporting Procedures	04/01/05
MOD-012-0	Dynamics Data for Transmission System Modeling and Simulation	04/01/05
MOD-013-0	RRO Dynamics Data Requirements and Reporting Procedures	04/01/05
MOD-014-0	Development of Interconnection-Specific Steady State System Models	04/01/05
MOD-015-0	Development of Interconnection-Specific Dynamics System Models	04/01/05
MOD-016-0	Actual and Forecast Demands, Net Energy for Load, Controllable DSM	04/01/05
MOD-017-0	Aggregated Actual and Forecast Demands and Net Energy for Load	04/01/05
MOD-018-0	Reports of Actual and Forecast Demand Data	04/01/05
MOD-019-0	Forecasts of Interruptible Demands and DCLM Data	04/01/05
MOD-020-0	Providing Interruptible Demands and DCLM Data	04/01/05
MOD-021-0	Accounting Methodology for Effects of Controllable DSM in Forecasts	04/01/05
MOD-024-1	Verification of Generator Gross and Net Real Power Capability	04/01/06
MOD-025-1	Verification of Reactive Power Capability	01/01/07
PER-001-0	Operating Personnel Responsibility and Authority	04/01/05
PER-002-0	Operating Personnel Training	04/01/05
PER-003-0	Operating Personnel Credentials	04/01/05
PER-004-0	Reliability Coordination – Staffing	04/01/05
PRC-001-0	System Protection Coordination	04/01/05
PRC-002-0	Define and Document Disturbance Monitoring Equipment Requirements	04/01/05

PRC-003-1	Regional Requirements for Transmission and Generation Protection System Misoperations	05/01/06
PRC-004-1	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	08/01/06
PRC-005-1	Transmission and Generation Protection System Maintenance and Testing	05/01/06
PRC-006-0	Development and Documentation of Regional UFLS Programs	04/01/05
PRC-007-0	Assuring Consistency with Regional UFLS Programs	04/01/05
PRC-008-0	Underfrequency Load Shedding Equipment Maintenance Programs	04/01/05
PRC-009-0	UFLS Performance Following an Underfrequency Event	04/01/05
PRC-010-0	Assessment of the Design and Effectiveness of UVLS Program	04/01/05
PRC-011-0	UVLS System Maintenance and Testing	04/01/05
PRC-012-0	Special Protection System Review Procedure	04/01/05
PRC-013-0	Special Protection System Database	04/01/05
PRC-014-0	Special Protection System Assessment	04/01/05
PRC-015-0	Special Protection System Data and Documentation	04/01/05
PRC-016-0	Special Protection System Misoperations	04/01/05
PRC-017-0	Special Protection System Maintenance and Testing	04/01/05
PRC-020-1	Under-Voltage Load Shedding Program Database	05/01/06
PRC-021-1	Under-Voltage Load Shedding Program Data	08/01/06
PRC-022-1	Under-Voltage Load Shedding Program Performance	05/01/06
TOP-001-0	Reliability Responsibilities and Authorities	04/01/05
TOP-002-0	Normal Operations Planning	04/01/05
TOP-003-0	Planned Outage Coordination	04/01/05
TOP-004-0	Transmission Operations	04/01/05
TOP-005-1	Operational Reliability Information	11/01/06
TOP-006-0	Monitoring System Conditions	04/01/05
TOP-007-0	Reporting SOL and IROL Violations	04/01/05
TOP-008-0	Response to Transmission Limit Violations	04/01/05
TPL-001-0	System Performance Under Normal Conditions	04/01/05
TPL-002-0	System Performance Following Loss of a Single BES Element	04/01/05
TPL-003-0	System Performance Following Loss of Two or More BES Elements	04/01/05
TPL-004-0	System Performance Following Extreme BES Events	04/01/05
TPL-005-0	Regional and Interregional Self-Assessment Reliability Reports	04/01/05
TPL-006-0	Assessment Data from Regional Reliability Organizations	04/01/05
VAR-001-0	Voltage and Reactive Control	04/01/05
	Glossary of Terms Used in Reliability Standards	02/08/05

APPENDIX B: STANDARDS WITH UNCLEAR ENFORCEABILITY UNDER EPACT 2005

NERC identifies 25 standards that are not enforceable with penalties. The following are the 28 standards identified by staff to have total or partial applicability to Regional Reliability Organizations. Such entities are not explicitly Owners, Operators, or Users of the Bulk-Power System, as defined by EPAct 2005, and therefore enforcement of these standards under EPAct 2005 is unclear.

Standard Number	Title
BAL-002-0	Disturbance Control Performance (partial)
EOP-004-0	Disturbance Reporting (partial)
EOP-007-0	Establish, Maintain, and Document a Regional Black start Capability Plan
FAC-003-1	Transmission Vegetation Management Program (partial)
IRO-001-0	Reliability Coordination – Responsibilities and Authorities (partial)
MOD-001-0	Documentation of TTC and ATC Calculation Methodologies
MOD-002-0	Review of TTC and ATC Calculations and Results
MOD-003-0	Procedure for Input on TTC and ATC Methodologies and Values
MOD-004-0	Documentation of Regional CBM Methodologies
MOD-005-0	Procedure for Verifying CBM Values
MOD-008-0	Documentation and Content of Each Regional TRM Methodology
MOD-009-0	Procedure for Verifying TRM Values
MOD-011-0	Regional Steady-State Data Requirements and Reporting Procedures
MOD-013-0	RRO Dynamics Data Requirements and Reporting Procedures
MOD-014-0	Development of Interconnection-Specific Steady State System Models
MOD-015-0	Development of Interconnection-Specific Dynamics System Models
MOD-016-0	Determination of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, Controllable DSM (partial)
MOD-024-1	Verification of Generator Gross and Net Real Power Capability (partial)
MOD-025-1	Verification of Generator Gross and Net Real Power Capability (partial)
PRC--002-0	Define and Document Disturbance Monitoring Equipment Requirements
PRC-003-1	Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems
PRC-006-0	Development and Documentation of Regional UFLS Program
PRC-012-0	Special Protection System Review Procedure
PRC-013-0	Special Protection System Database
PRC-014-0	Special Protection System Assessment
PRC-020-1	Under-Voltage Load Shedding Program Database
TPL-005-0	Regional and Interregional Self-Assessment Reliability Reports
TPL-006-0	Assessment Data from Regional Reliability Organizations

APPENDIX C: STANDARDS LACKING MEASURABILITIY AND NON-COMPLIANCE SPECIFICATIONS

In its Request for Approval of Reliability Standards, NERC identifies 21 standards without provisions in the Measures or Levels of Non-Compliance sections of the standard. The following is a list of 26 standards identified by staff without provisions for either Measures, or Levels of Non-Compliance, or both.

Standard Number	Title
BAL-003-0	Frequency Response and Bias
BAL-004-0	Time Error Correction
BAL-005-0	Automatic Generation Control
BAL-006-0	Inadvertent Interchange
CIP-001-0	Sabotage Reporting
COM-001-0	Telecommunications
COM-002-0 or COM-002-1	Communications and Coordination
EOP-003-0	Load Shedding Plans
EOP-004-0	Disturbance Reporting
EOP-005-0	System Restoration Plans
EOP-006-0	Reliability Coordination – System Restoration
INT-001-0	Interchange Transaction Tagging
INT-002-0	Interchange Transaction Tag Communication and Assessment
INT-003-0	Interchange Transaction Implementation
INT-004-0	Interchange Transaction Modifications
IRO-002-0	Reliability Coordination – Facilities
IRO-003-0 or IRO-003-1	Reliability Coordination – Wide Area View
IRO-005-0 or IRO-005-1	Reliability Coordination – Current Day Operations
PER-004-0	Reliability Coordination – Staffing
PRC-001-0	System Protection Coordination
TOP-001-0	Reliability Responsibilities and Authorities
TOP-002-0	Normal Operations Planning
TOP-004-0	Transmission Operations
TOP-006-0	Monitoring System Conditions
TOP-008-0	Response to Transmission Limit Violations
VAR-001-0	Voltage and Reactive Control

APPENDIX D: ACRONYMS IN THIS DOCUMENT

ACE	Area Control Error
AGC	Automatic Generation Control
ANSI	American National Standards Institute
ATC	Available Transfer Capability
BAL	Resource and Demand Balancing category in the NERC Reliability Standards
BCP	Blackstart Capability Plan
BES	Bulk Electric System
BPS	Bulk-Power System
CBM	Capacity Benefit Margin
CIP	Critical Infrastructure Protection category in the NERC Reliability Standards
COM	Communications category in the NERC Reliability Standards
CPS1/CPS2	Control Performance Standard 1 / Control Performance Standard 2
DC	Direct Current
DCS	Disturbance Control Standard
EOP	Emergency Preparedness and Operations category in the NERC Reliability Standards
ERO	Electric Reliability Organization
FAC	Facilities Design, Connections and Maintenance category in the NERC Reliability Standards
FPA	Federal Power Act
GWh	Gigawatt hour
IEEE	Institute of Electrical and Electronic Engineers
INT	Interchange Scheduling and Coordination category in the NERC Reliability Standards
IRO	Interconnection Reliability Operations and Coordination category in the NERC Reliability Standards
IROL	Interconnection Reliability Operating Limits

MOD	Modeling, Data, and Analysis category in the NERC Reliability Standards
MW	Mega Watt
NERC	The North American Electric Reliability Corporation and the North American Electric Reliability Council are separately or collectively referred to as NERC
NPCC	Northeast Power Coordinating Council
PER	Personnel Performance, Training, and Qualifications category in the NERC Reliability Standards
PRC	Protection and Control category in the NERC Reliability Standards
RRO	Regional Reliability Organization
ROW	Right of Way
SOL	System Operating Limit
SPS	Special Protection System
TIS	Transmission Issues Subcommittee
TOP	Transmission Operations category in the NERC Reliability Standards
TLR	Transmission Loading Relief
TPL	Transmission Planning category in the NERC Reliability Standards
TRM	Transmission Reliability Margin
TTC	Total Transfer Capability
UA-1200	Urgent Action Standard - 1200
UFLS	Under Frequency Load Shedding
UVLS	Under Voltage Load Shedding
VAR	Voltage and Reactive category in the NERC Reliability Standards
WECC	Western Electricity Coordinating Council

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November 28, 2005

Ms. Julia Souder
Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, D.C 20585

Re: Notice of Intent to Prepare a Programmatic Environmental Impact Statement, Amended Relevant Agency Land Use Plans, Conduct Public Scoping Meetings, and Notice of Floodplain and Wetlands Involvement, FR Vol. 70, No. 187, page 56447 (September 28, 2005)

Dear Ms. Souder.

Arizona Public Service Company ("APS") appreciates the opportunity to comment on the Notice of Intent to prepare a draft Programmatic Environmental Impact Statement ("PEIS") implementing Section 368 of the Energy Policy Act of 2005 (P.L. 109-58) ("2005 EPAct"). APS spoke at the Public Scoping Meeting ("Scoping Meeting") held in Phoenix, Arizona on November 3, 2005 and incorporates the comments it made at the Scoping Meeting. APS also supports the comments submitted by the Edison Electric Institute ("EEI") and incorporates them here by reference. Finally, as indicated during the Public Scoping meeting, APS hopes to continue to be a partner with the Departments of Energy, Interior and Agriculture ("Departments") as they complete the preparation of the PEIS.

Annual system load growth throughout the Southwest is 3-5%, which is approximately three times the national average. APS, which is the largest electric utility in Arizona, serves more than 1 million customers in 11 of the state's 15 counties. The APS service territory is one of the fastest growing in the country and covers federal, state and tribal lands. APS continually evaluates where it needs both new and upgraded transmission facilities to serve its customers needs. Many of the transmission lines constructed and operated by APS cross federal lands, as well as state, tribal and privately owned lands. APS has worked successfully with various federal agencies in the past to develop utility corridors that have

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been incorporated into the agencies' Resource Management Plans. Attachment 1 is a map showing the existing transmission system in Arizona. Attachment 2 is a map showing APS's current plans for new facilities between 2005-2014. Attachment 3 is a map identifying existing corridors in Arizona that could be widened and potential new corridors that APS believes would be beneficial for currently planned facilities and facilities that may be needed outside the current planning horizon. APS requests that the Departments use the information in these maps to identifying and designate utility corridors to be incorporated into the Departments' Resource Management Plans.

APS will continue its detailed analysis to identify additional specific corridors to recommend for the Departments' consideration and will submit that information as soon as it becomes available.

In order to access future base load coal-fired generation and renewable resources, APS recently announced the initiation of a feasibility study for two 500,000-volt (500-kV) transmission lines from Wyoming to northern Arizona ("TransWest Express Project" or "Project"). The completion of the TransWest Express Project would provide Arizona and other western states increased capability to access electricity generated from coal, wind and other resources in Wyoming. Additional information regarding the TransWest Express Project is provided below. Again, as APS identifies more specific corridors for the TransWest Express Project, that information will be submitted for the Departments' consideration in preparing the PEIS.

General Recommendations

Like EEI, APS believes that Alternative 4, the Optimization Criteria Alternative, set forth in the Notice of Intent best accommodates the objectives underpinning the 2005 EPAct and should be the preferred alternative for the PEIS. Alternative 4 takes into account critical elements important for sound transmission planning while providing the best assurance that the required environmental review and analysis are completed early in the process, thereby allowing for expedited procedures when the time comes to site (or upgrade) a line within a designated corridor.

To most effectively complete the PEIS process within the time frame provided in the 2005 EPAct, APS encourages the Departments to look to the work already done or underway by regional planning groups with detailed knowledge of the regions at issue. In the Western Interconnection these groups include:

- Seams Steering Group – Western Interconnection (SSG-WI
- Colorado Coordinating Planning Group (CCPG)
- Northwest Transmission Assessment Committee (NTAC)
- Rocky Mountain Area Transmission Study group (RMATS)

- Southwest Transmission Expansion Plan group (STEP)
- Southwest Area Transmission group (SWAT).

The work already completed or underway by these groups will assist the Departments in identifying necessary and appropriate utility corridors, as those regional groups, along with the specific utilities affected, best understand what is needed to ensure system reliability and address congestion concerns. In addition, APS recommends that the Departments take into consideration the work reflected in the 2003 Western Regional Corridor Planning Priority Corridors map (and its predecessors), which was prepared in cooperation with federal land management agencies

APS strongly urges the Departments to designate specific energy corridors through the PEIS process where it is feasible to do so. At a minimum, those corridors should include the corridors already being utilized by existing 69 kV and above transmission lines crossing federal lands. APS also encourages the Departments to assess the feasibility of converting or expanding those existing corridors to accommodate additional or upgraded transmission facilities. To the extent possible, the Department also should designate new corridors for transmission lines to meet the needs expressed through the regional planning processes and by the individual utilities, and that are consistent with environmental constraints APS has undertaken a process to identify proposed corridors to meet its anticipated needs and will submit that information as it is developed. APS further recommends that the Departments include new corridors for future 69 kV and distribution facilities, particularly on U.S. Forest Service lands APS suggests that, wherever possible, such corridors should follow existing linear features (*e.g.*, highways, U.S. Forest Service roads, and existing utility lines). Finally, APS strongly urges the Departments to ensure that after the PEIS is completed, the same NEPA analysis does not have to be redone for a minimum of ten years.

It is essential that the Departments work with other affected jurisdictions (states, local communities, and tribes) to enhance coordination and timely permitting of transmission lines. The ability to cross state, local and tribal lands, particularly in the west, is critical to the siting of transmission facilities APS also encourages the Departments to consult with the Western Governors Association. If the Departments can designate corridors that coordinate with the preferences of the affected states and tribes, the value of such corridor designations will only be enhanced.

Once a transmission line is sited and constructed within a designated utility corridor across federal lands, the corridor should remain a utility corridor until it no longer is needed for the transmission facilities located within it. Thus, any transfers of federal lands should, at a minimum, require the transferee to maintain the utility corridor, avoid conflicting uses, and maintain terms consistent with a federal right-of-way In addition, APS encourages the Departments to develop enforceable guidelines to prevent the placement of incompatible uses in the same corridor, as well as to prevent encroachment on the corridors by incompatible uses Although there are a number of uses compatible with transmission lines, and there is value in corridors being used for more than one compatible purpose, APS believes that certain uses are incompatible with transmission facilities.

Of equal importance to the designation and protection of utility corridors in the PEIS, however, is the development of procedures for (i) designation of additional corridors in the future and (ii) a streamlined process to ensure expedited compliance with the National Environmental Policy Act ("NEPA") for lines to be sited within previously designated energy corridors on federal lands. With respect to the designation of future corridors, it is important that the corridors developed through the PEIS process not preclude a siting application outside such corridors, nor should such a siting process be made any more difficult than under currently existing regulations.

With respect to the siting of facilities within already designated corridors, it should be clear that so long as the facilities are consistent with the parameters established for a corridor, no more than an Environmental Assessment should be needed to satisfy NEPA. At a minimum, work that has already been completed should not have to be repeated when a siting application is submitted for a previously designated corridor.

APS also encourages the Departments to develop consistent vegetation management practices on federal lands so that utilities are able to comply with the NERC Transmission Vegetation Management Standard.

Specific Recommendations

Corridor widths identified by federal land management agencies in their management plans currently vary between agencies APS recommends that all corridors designated under the PEIS be three to five miles wide. Such widths will provide the flexibility necessary to avoid environmentally sensitive areas, address engineering, technical and vegetation management constraints, and allow lines to be built with sufficient separation to reduce the risk of simultaneous outage of multiple lines. Those widths also would accommodate the need for access roads and temporary construction activities Closely paralleled lines in a common corridor may have a high probability of common mode outage, which would result in a lower path rating based upon Western Electric Coordinating Council ("WECC") planning criteria. Wider corridor widths also provide flexibility to meet separation requirements necessary to accommodate various uses within the same corridor

Environmental Issues

APS recommends that the following four environmental resource categories be evaluated to determine opportunities and constraints for locating utility corridors: (1) land use (jurisdiction, existing and future land use, recreation, and utilities); (2) visual (most land management agencies have defined visual resources and determined management levels); (3) cultural (archaeological, historical and traditional cultural properties); and (4) biology (vegetation, wildlife, habitat, threatened and endangered species, etc). APS believes that the best opportunities for utility corridors typically are (1) corridors following linear features, such as existing or future transmission lines, roads, railroads, pipelines, linear communication facilities (*e.g.*, fiber optic lines), canals, and jurisdictional lines, or (2) areas with low resource sensitivity. The PEIS should comprehensively evaluate cumulative effects (future NEPA documents could refer to these results), land values, and environmental justice issues, among others. Corridor widths of three to five miles will facilitate the siting of new transmission facilities in a manner that is more compatible with environmental concerns because such widths will provide the flexibility needed to avoid or mitigate harm to such resources

Jurisdictional Issues

A large portion of the land in the western United States is under federal, state or tribal jurisdiction. Several federal land designations currently limit new transmission lines In such areas, it is even more important for corridor widths to be expanded to three to five miles to allow future lines to be sited in a manner that minimizes impact to the environment and ensures system reliability. The following paragraphs set forth specific examples where such issues may arise

- National Recreation Areas – National recreation areas, currently under the management of the National Park Service, should allow for future lines through wider corridor widths of three to five miles

- National Monuments – Recently designated (2001) National Monuments in the west contained corridors critical to future transmission line projects Currently, however, the National Monument designations prohibit any new transmission lines. APS encourages the Department to consider widening the existing corridors and opening them to new lines.

- Military Lands – Military lands have blocked potential transmission lines or have low height restrictions across vacant lands that prohibit future line development It is important for the Departments to work with the military facilities to identify utility corridors to allow siting of new facilities while protecting military uses.

- U S. Fish and Wildlife Service Lands – U.S Fish and Wildlife Service lands currently have restrictions that block future lines and should be evaluated for possible corridor widening

- Other Federal Designations – Lines in proximity to certain federal land designations, such as wilderness areas, generally are forced to locate elsewhere regardless of the cost and environmental impacts (even when an area currently has existing lines).

Alternatives to expensive bypass routing should be given serious consideration by the Departments.

- Indian Reservations – Numerous lines cross reservations and more will be needed in the future for wheeling of energy throughout the west. APS strongly urges the Departments to invite the tribes throughout the west to participate in the planning process and to encourage those tribes to designate utility corridors that coincide with utility corridors designated on adjacent federal lands. The designation of corridors three to five miles wide would allow for alternatives to be evaluated that can accommodate the needs and desires of the tribes impacted by a transmission line In addition, however, alternatives that bypass the reservations should be planned and included in the PEIS For example, between Arizona, Utah, Colorado, or New Mexico, numerous reservations restrict new lines traveling north/south and east/west. Alternatives are necessary to avoid these reservations while serving the growing needs of the southwest.

- State Lands – APS also urges the Departments to invite the western states to participate in the PEIS process. Because of the large amount of state land in Arizona, the Departments should work with the Arizona State Land Department to identify state preferences for the location of utility corridors.

- Zoning – Corridor designations should take into account local and county plans and zoning decisions wherever possible

TransWest Express Project

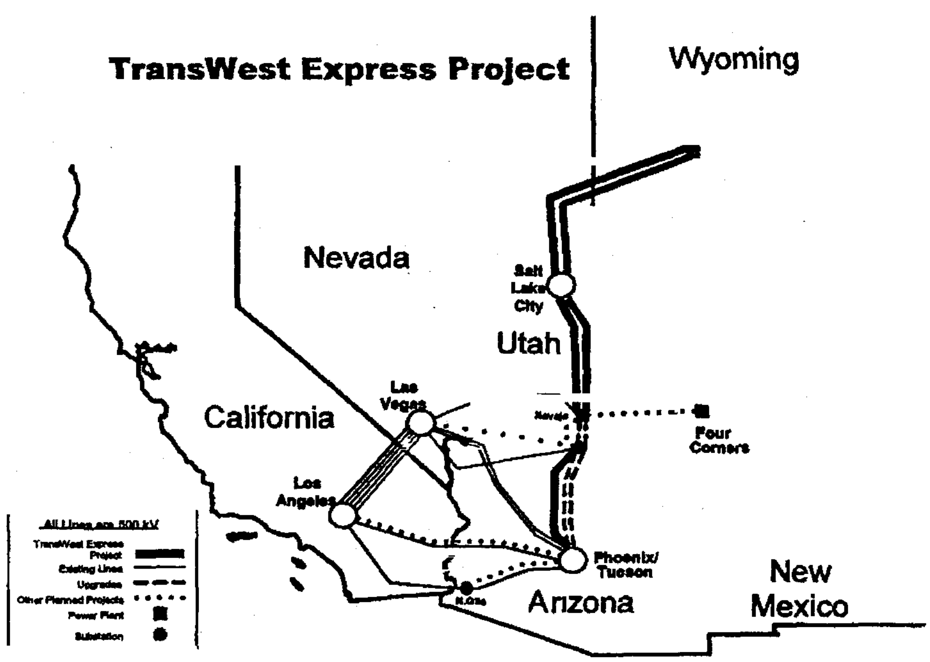
As mentioned above, APS recently announced the TransWest Express Project. APS is seeking input and participation of interested parties to jointly examine the technical and economic feasibility of the Project, as well as the relevant environmental and regulatory considerations This joint feasibility analysis will be performed within the various regional and sub-regional transmission planning groups and reliability organizations in the West. An open stakeholder project kick-off meeting was held in Phoenix on November 17, 2005 and was attended by approximately 75 interested parties

The Project initially will be modeled as two parallel 500kV AC transmission lines starting at the Jim Bridger station in Southwestern Wyoming. The Project seeks to access coal, wind and other resources in Wyoming and there may be additional transmission included in the Project into that region. From Jim Bridger, the Project could go into the Wasatch Front area of Utah to serve load in the Salt Lake City area and then go south through Utah across the Arizona border to terminate at the Navajo 500kV station The Project will be a minimum of 600 miles in length depending on the route(s) selected and where the Project terminates in Wyoming The Project cost is estimated to be in excess of $3 billion

In addition to the new transmission lines, the feasibility study will also assess the benefits of integrating these new facilities with other transmission projects already announced or planned, including the Dine Navajo Transmission Project, the Palo Verde – Devers #2 Project, the Palo Verde - North Gila #2 Project, and planned upgrades to the existing Navajo Transmission System lines and the Mead – Phoenix line It is anticipated that with these existing planned transmission projects, the TransWest Express Project also will provide significant benefit and opportunity for remote resource access to Southern Nevada and Southern California The feasibility study also will assess the benefits of a third line from the Navajo Generating Station in northern Arizona to the Phoenix area (see map below).

The Phase 1 feasibility study is expected to take about one year Phase 2 of the Project would include obtaining required permits and other approvals and a WECC Project rating Phase 3 would include construction and operation of the Project, with an expected in-service date of 2013.

Below is a conceptual line route As the feasibility analysis is completed, a more definite route will be identified and, if the project proceeds, a final route will be pursued. APS will keep the Agencies informed as the Project route develops and will pursue siting through the regulatory process in each of the affected states



Also included at Attachment 4 is a map that, in addition to reflecting the same corridors shown on Attachment 3, identifies additional potential corridors for the TransWest Express Project APS requests that the Departments widen all of the existing corridors indicated on the map and designate the additional proposed corridors as utility corridors in the PEIS.

APS looks forward to working with you and the Departments throughout the preparation of the PEIS. As indicated above, APS will provide additional information as it completes its current assessment of corridor needs In the meantime, if you have any questions, please feel free to contact me

Sincerely,

Arizona Public Service Company

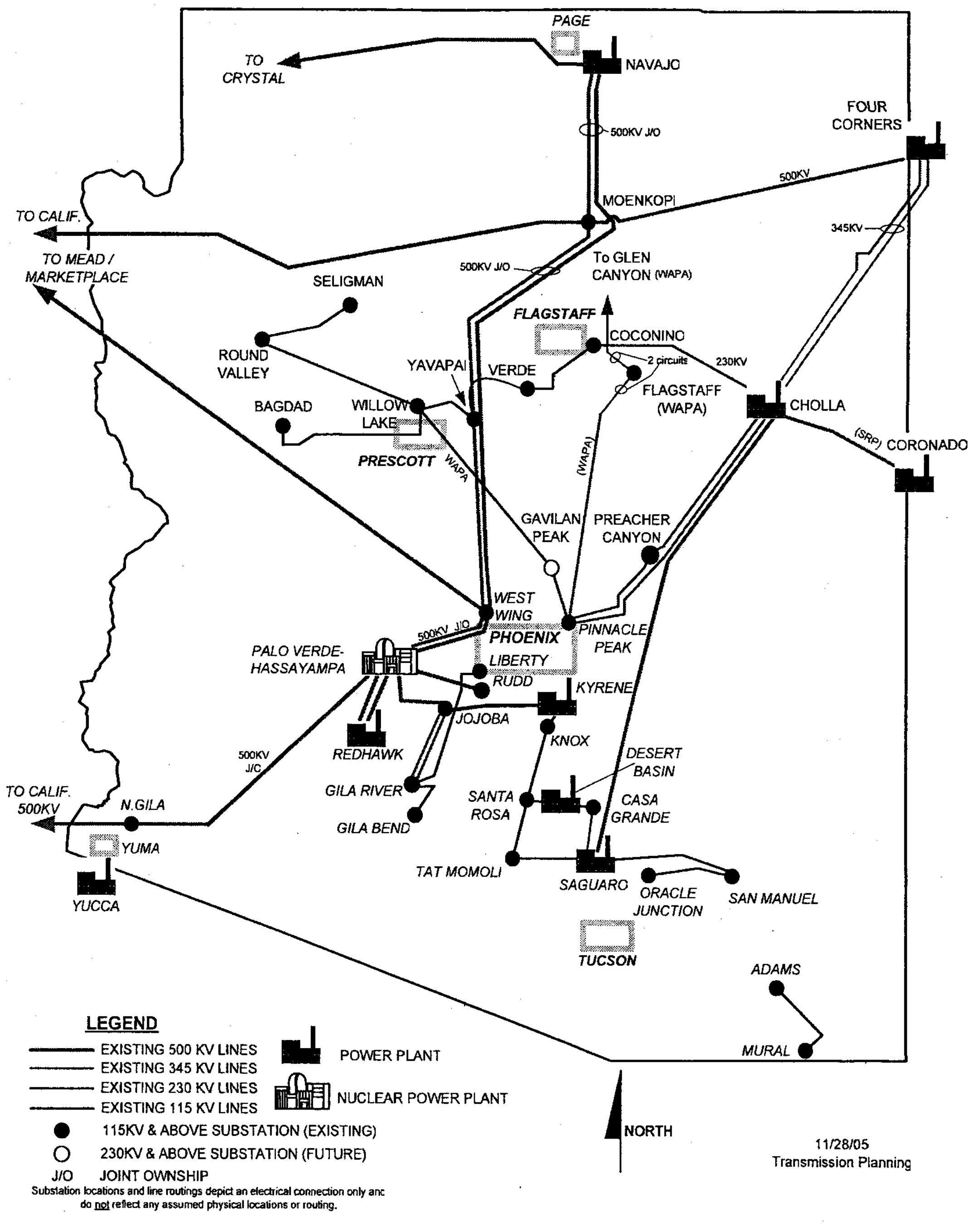
Karilee S Ramaley

By Karilee S Ramaley

cc: Robert D Smith, APS
Paul E. Herndon, APS

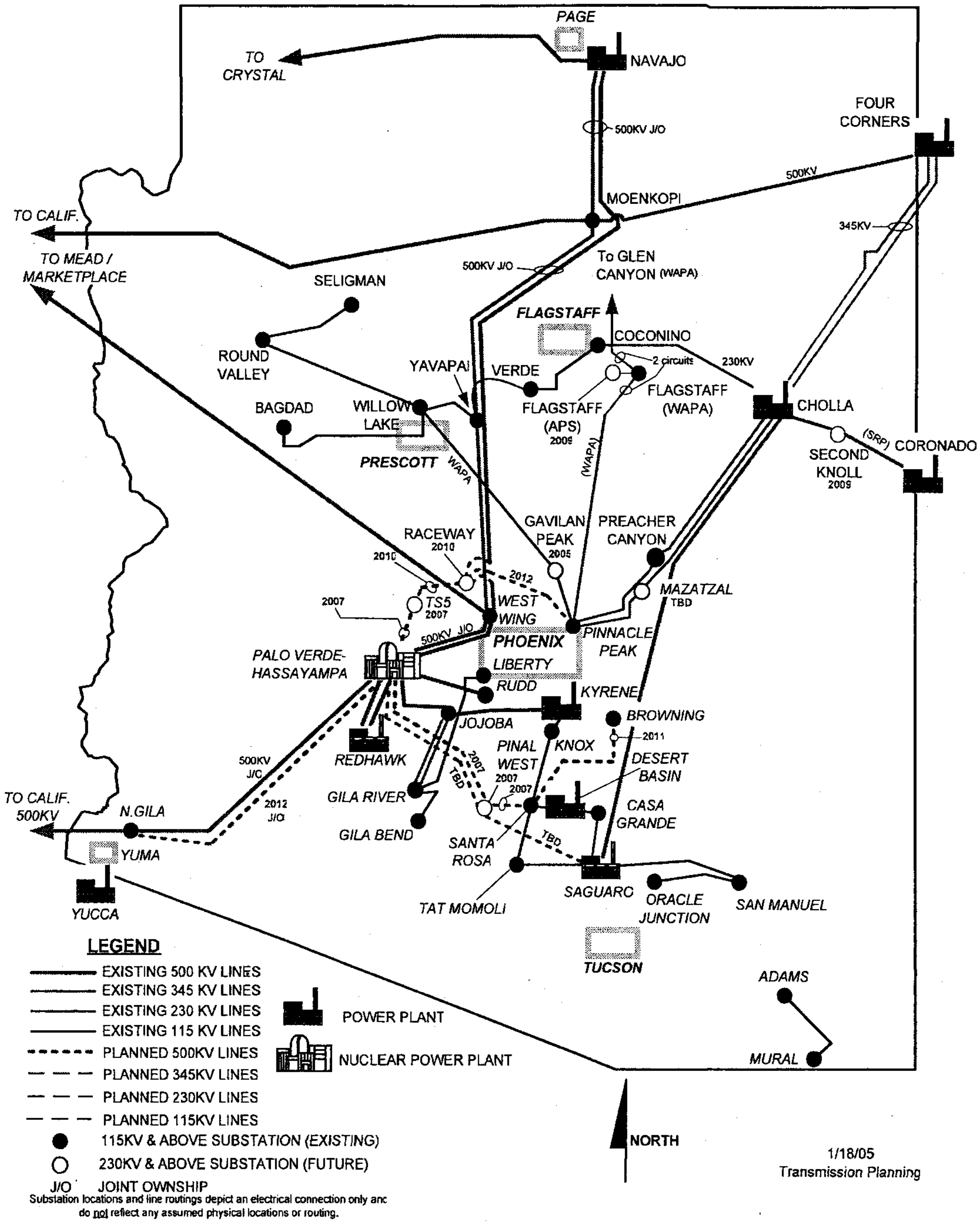
ATTACHMENT 1

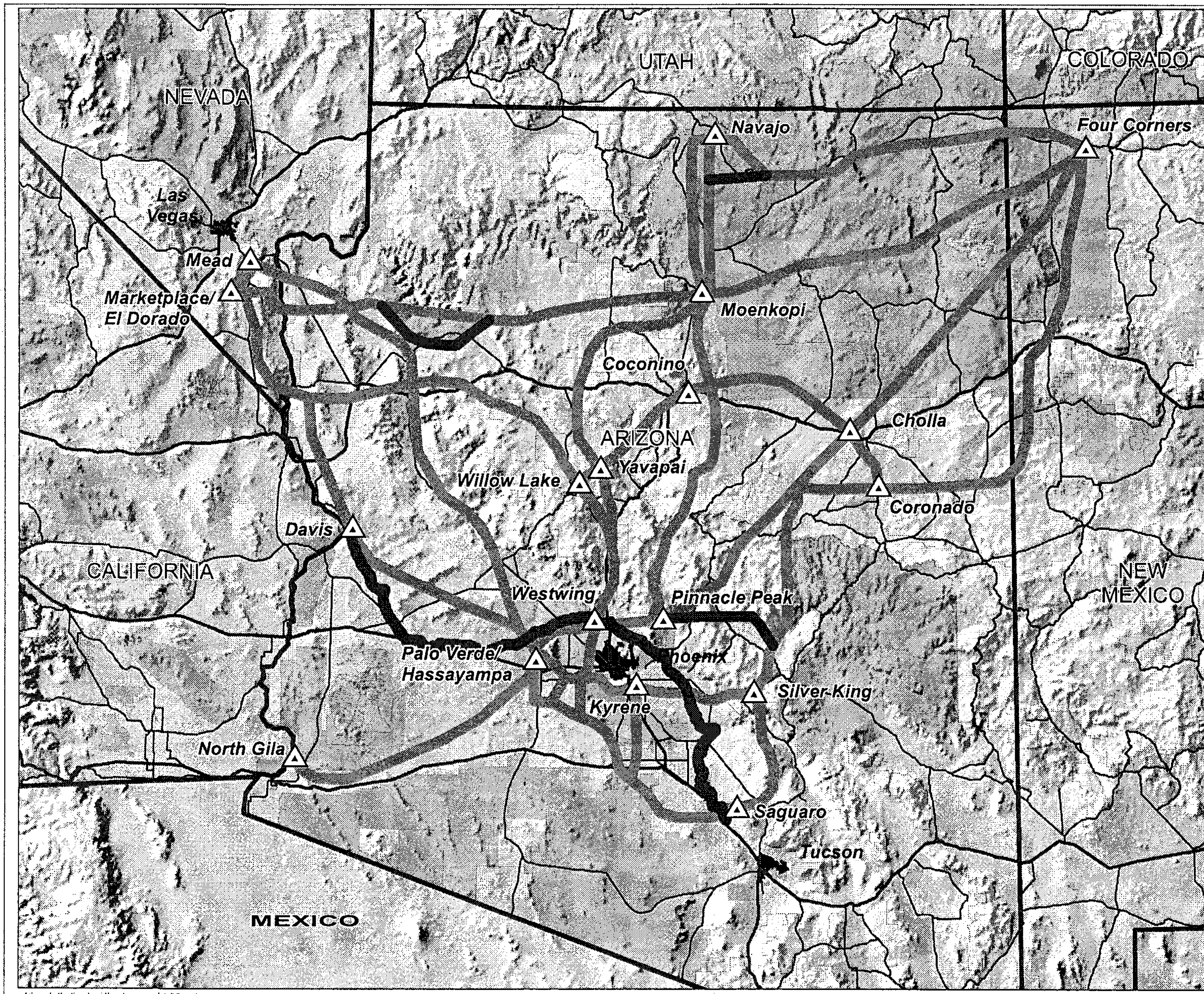
2005 APS TRANSMISSION SYSTEM



ATTACHMENT 2

APS EHV & OUTER DIVISION 115/230 KV TRANSMISSION PLANS 2005 - 2014





APS EXISTING AND PROPOSED PROJECTS/CORRIDORS

Attachment 3

LEGEND

- Corridors containing existing transmission facilities that should be widened
- Corridors with no existing transmission facilities that should be designated for future facilities
- Bureau of Land Management
- Bureau of Indian Affairs
- U.S. Forest Service
- National Park Service
- Department of Defense
- U.S. Fish & Wildlife Service
- State/Private

REFERENCE FEATURES

- State Boundary
- Major Interstate/Highway
- Substation

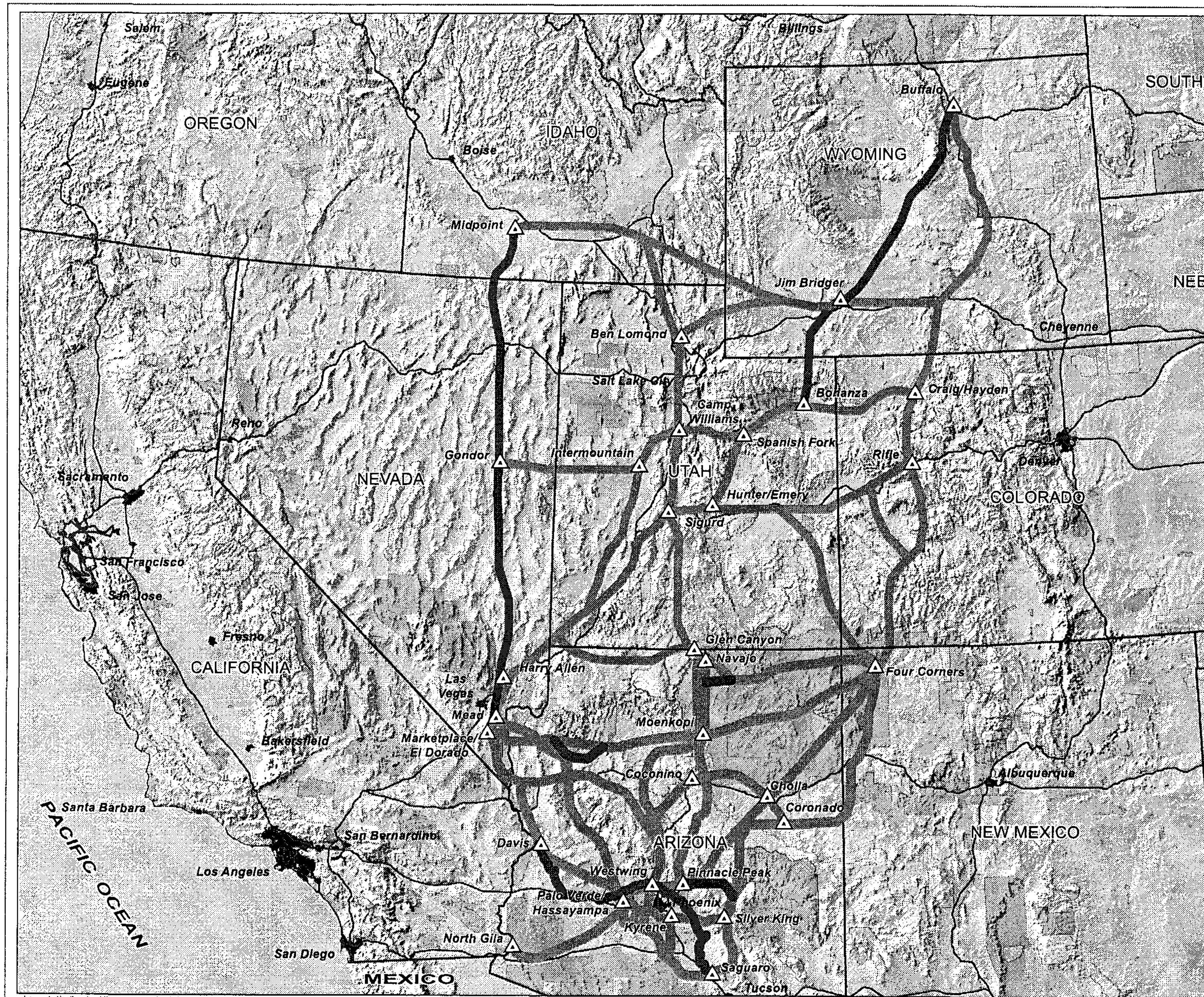
Data Source Information

Land Ownership and BLM Field Office Boundaries: BLM Denver Service Center, 2004.

NOTE: Transmission corridors and substation locations are schematics and do not necessarily represent precise locations.

November 28, 2005

APS



TransWest Express Project

Potential Corridors

Attachment 4

LEGEND

- Corridors containing existing transmission facilities that should be widened
- Corridors with no existing transmission facilities that *should be designated for future projects*
- Bureau of Land Management
- Bureau of Indian Affairs
- U.S. Forest Service
- National Park Service
- Department of Defense
- U.S. Fish & Wildlife Service
- State/Private

REFERENCE FEATURES

- State Boundary
- Major Interstate
- Major Substation

0 12.525 50 75 100 Miles

Data Source Information

Land Ownership and BLM Field Office Boundaries: BLM Denver Service Center, 2004.

NOTE: Transmission corridors and substation locations are schematics and do not necessarily represent precise locations.

November 28, 2005

APS

APS *A subsidiary of Pinnacle West Capital Corporation*

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Mail Station 2259
PO Box 53999
Phoenix, Arizona 85072-3999

March 6, 2006

Office of Electricity Delivery and Energy Reliability, OE-20
Attn: EPACT 1221 Comments
U.S. Department of Energy
Forestall Building, Room 6H-050
1000 Independence Avenue, SW
Washington, D.C. 20585

Re: Notice of Inquiry regarding Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, FR Vol. 71, No. 22, page 5660 (February 2, 2006)

To Whom It May Concern:

Arizona Public Service Company ("APS") appreciates the opportunity to provide initial comments to the U.S. Department of Energy ("DOE") regarding Notice of Inquiry on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors, FR Vol. 71, No. 22, page 5660 (February 2, 2006) ("NOI"). APS supports the comments submitted by the Edison Electric Institute ("EEI") and incorporates them here by reference.

Like EEI, APS generally supports the process undertaken by DOE to identify potential National Interest Electric Transmission Corridors ("NIETC"). APS applauds DOE's intent to take into account the work already underway or completed by regional planning groups in the West. APS believes that the use of studies and other information developed by those regional planning groups, combined with additional information developed through the current process, will allow the DOE to produce a report that clearly identifies the areas that meet the criteria for NIETC designation. APS also supports generally the criteria that DOE has identified for NIETC designation, as modified by EEI. APS encourages DOE to make its initial NIETC designations as soon as reasonably possible to further facilitate infrastructure development.

Annual system load growth throughout the Southwest is 3-5%, which is approximately three times the national average. APS, which is the largest electric utility in Arizona, serves one of the fastest growing areas in the country and that area covers federal, state and tribal lands. APS continually evaluates its need for new and upgraded transmission facilities, as well as for generation resources to serve its customers needs.

Based on APS's assessment of its future resource needs, including both transmission and generation, APS announced the TransWest Express Project in 2005. That project, which initially will be modeled as two 500kV AC transmission lines from Wyoming to the Southwest, seeks to provide access for APS and the Southwest to coal, wind and other resources in Wyoming. The initial routes under consideration for that project are consistent with and supported by both the Report to the Western Governors Association titled "Conceptual Plans for Electricity Transmission in the West" (August 2001) and the Rocky Mountain Area Transmission Study (RMATS) report. Both of those reports noted that electric transmission in the West is constrained and that those constraints result in the underutilization of the region's vast wind and coal resources, thereby demonstrating the need for additional transmission from the Wyoming area to the Southwest.

APS also believes that the TransWest Express Project meets several of the criteria identified by DOE in the NOI. APS currently is conducting a technical and economic feasibility analysis for the TransWest Express Project. APS also is examining the relevant environmental and regulatory considerations surrounding the project. APS contemplates that the feasibility analysis will be performed within the various regional and sub-regional transmission planning groups and reliability organizations in the West. In addition to studying the TransWest Express Project, the feasibility study will assess the benefits of integrating the project with other transmission projects already announced or planned. It is anticipated that along with other announced transmission projects, the TransWest Express Project will provide significant benefit and opportunity for remote resource access to Southern Nevada and Southern California as well as to Arizona. As the feasibility analysis proceeds, APS will provide additional information to DOE.

APS looks forward to participating in the process undertaken by DOE for implementing Section 1221(a) of the Energy Policy Act, including providing comments on the draft congestion study and potentially proposing specific transmission corridor(s) that APS believes are suitable for NIETC designation. In the meantime, if you have any questions, please feel free to contact me at 602-250-1144 or Robert.Smith@aps.com or Karilee Ramaley at 602-250-3626 or Karilee.Ramaley@pinnaclewest.com.

Sincerely,

R.D. Smith

By Robert D. Smith

Cc: Karilee S. Ramaley