From:	Howard Gugel
To:	rsg
Subject:	NERC - RSG - Whitepaper on Regional Standards and Variances
Date:	Monday, November 28, 2011 5:03:07 PM
Attachments:	Whitepaper on Regional Standards and Variances combined comments - Nov 28.docx

Attached is the whitepaper as modified on the call today. We reviewed down to the "Stopped here" line. We will discuss on our next RSG call if/when we would like to do another call prior to the face to face meeting in January. Thanks again for your assistance in refining this document and determining how regional standards and variances should proceed.

When reviewing this document, the comments assigned HLG are Guy's comments from his email on November 28. I combined these documents for ease in analysis.

Howard Gugel
Manager of Regional Standards
NERC
(609) 651-2269
howard.gugel@nerc.net

NERC. Reliability. Accountability.

This email and any of its attachments may contain NERC proprietary information that is privileged, confidential, or subject to copyright belonging to NERC. This message and any attachments may contain confidential information protected by the attorney-client or other privilege. This email is intended solely for the use of the individual or entity to which it is addressed. If you are not the intended recipient of this email, you are hereby notified that any dissemination, distribution, copying, or action taken in relation to the contents of and attachments to this email is strictly prohibited and may be unlawful. If you receive this email in error, please notify the sender immediately and permanently delete the original and any copy of this email and any printout.

Y

Where to Put Requirements that Apply on Less Than a Continent-wide Basis

Regional Standards and Variances – *What was Approved in the ERO Certification Order and Rules of Procedure*

FERC has indicated it will consider approving regional differences (variances) and Regional Standards that meet the following criteria:

Item 34: ¶ 274 of the ERO Certification Order:

> "The Commission has stated that we will accept the following two types of regional differences, provided they are otherwise just, reasonable, not unduly discriminatory or preferential and in the public interest, as required under the statute:
>
> (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and
>
> (2) a regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System.

The FERC-approved definitions of Regional Standard and Variance (from the Rules of Procedure) are:

> **"Regional reliability standard"** means a type of reliability standards that is applicable only within a particular regional entity or group of regional entities. A regional reliability standard may augment, add detail to, or implement another reliability standard or cover matters not addressed by other reliability standards. Regional reliability standards, upon adoption by NERC and approval by the applicable ERO governmental authority(ies), shall be reliability standards and shall be enforced within the applicable regional entity or regional entities pursuant to delegated authorities.
>
> **"Variance"** means an aspect or element of a reliability standard that applies only within a particular regional entity or group of regional entities, or to a particular entity or class of entities. A variance allows an alternative approach to meeting the same reliability objective as the reliability standard, and is typically necessitated by a physical difference. A variance is embodied within a reliability standard and as such, if adopted by NERC and approved by the ERO governmental authority, shall be enforced within the applicable regional entity or regional entities pursuant to delegated authority.

Regional Standards and Variances – *What was Approved in the Standard Processes Manual*

The latest approved version of the Standard Processes Manual includes the following language:

> NERC's drafting teams shall aim to develop standards with requirements that apply on a continent-wide basis, minimizing the need for variances while still achieving the standard's reliability objectives. If one or more requirements cannot be met or complied with as written because of a physical difference in the bulk power system or because of an operational difference (such as a conflict with a Federally or Provincially approved tariff), but the requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a variance from

DRAFT

one or more requirements in a continent-wide standard. It is the responsibility of the entity that needs a variance to identify that need and initiate the processing of that variance through the submittal of a SAR that includes a clear definition of the basis for the variance.

There are two types of variances – those that apply on an interconnection-wide basis, and those that apply to one or more entities on less than an interconnection-wide basis.

Interconnection-wide Variances

Any variance from a NERC reliability standard requirement that is proposed to apply to responsible entities within a regional entity organized on an interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that regional entity's NERC-approved regional reliability standards development procedure.

While an interconnection-wide variance may be developed through the associated Regional Entity standards development process, regional entities are encouraged to work collaboratively with existing continent-wide drafting team to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC reliability standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC reliability standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC reliability standard that is developed, in accordance with a standards development procedure approved by NERC, by a regional entity organized on an interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

Variances that Apply on Less than an Interconnection-wide Basis

Any variance from a NERC reliability standard requirement that is proposed to apply to one or more entities but less than an entire Interconnection (e.g., a variance that would apply to a regional transmission organization or particular market or to a subset of bulk power system owners, operators, or users), shall be considered a Variance. A Variance may be requested while a standard is under development or a Variance may be requested at any time after a standard is approved. Each request for a Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide standard, using the standards development process defined in this manual.

Regional Standards and Variances - *Requirements that Apply on Less than a Continent-wide Basis*

NERC's goal is to have a set of reliability requirements that provides an 'adequate level of reliability.' In some instances, a continent-wide standard cannot be written so that the desired level of reliability is attained with requirements that apply to all entities – in some instances an alternative requirement that mandates performance not addressed in the continent-wide requirements is needed to attain the desired level of reliability – and in some instances requirements with more stringent performance are needed to maintain an adequate level of reliability. Regional standards and variances give NERC the tools it needs to develop and maintain a core set of standards that apply throughout the continent – augmented by a small set of supplementary requirements that address unique situations where a continent-wide requirement is not necessary.

DRAFT

FERC, in its Orders, has indicated that it will apply a single set of criteria for approving both Regional Standards and Regional Differences.

Since all standards approved by NERC and applicable regulatory authorities are subject to the same level of enforceability – the location of a requirement (in a regional standard or a continent-wide standard) does not have any impact on either reliability or enforceability.

There are three ways of developing a requirement that identifies performance necessary for reliability that applies on less than a continent-wide basis:

- Within a continent-wide standard, a requirement can include alternative performance based on different facility characteristics, different regions, or different interconnections. (See INT-006-3 for an example.)
- A continent-wide standard can include a variance that specifies one or more alternative requirements that apply to a functional entity meeting certain characteristics[GVZ1], one or more Regions, or an Interconnection. (See FAC-011-2 for an example.)
- A regional standard ~~can~~will include mandatory ~~performance~~requirments that achieve a reliability objective ~~that is~~ needed for reliability ~~only~~ in that region. (See VAR-STD-002b-1 for an example.)

Each of these methods achieves the same goal – that of developing a requirement that specifies mandatory ~~performance~~requirments needed ~~for~~to achieve a reliability objective.

The process of developing and approving standards that apply on a Regional or Interconnection-wide basis differs from the process used to develop a continent-wide standard. ~~Typically, standards developed on a continent-wide basis are subject to more scrutiny because there is a broader population reviewing and providing comments on a continent-wide standard.~~ [GVZ2]

~~With limited resources to allocate to standard development, developing regional standards and continent-wide standards requiring very similar performance is not desired~~[GVZ3]. When a continent-wide standard is developed and there is a need to support the continent-wide standard with region-specific requirements, the region-specific requirements may be developed either as regional standards or ~~the regional performance can be embedded within the continent-wide standard's requirements~~a regional variance to the continent wide standard requirement. If it is determined that a variance is necessary, the development of the variance should occur during the development of the continent wide standard, if possible. ~~[COMMENT: Consider adding that the latter approach is preferred, if the region-specific need is identified while the CW standard is under development~~[GVZ4]~~.] In some cases, regional requirements that identify 'how' to implement a continent-wide standard may be developed as regional procedures rather than Regional Standards.~~[HLG5]

Some Regions have technical committees that study reliability issues and identify areas where new or different reliability requirements may be needed. If an region identifies a potential reliability "gap" it will take the necessary steps to fill that gap with either a Regional Standard~~, Criteria~~ or Variance with due consideration to NERC's existing projects and the ability of those projects to address the need. Before embarking on an effort to develop a set of requirements for a new regional standard, it would be beneficial to ~~determine~~ consider if the new/revised requirement should apply on a broader basis – to other regions, to an entire Interconnection, or to the entire continent. ~~[COMMENT: Most of the subjects for regional standards that have been recently discussed in Texas would apply equally on a continent-wide basis, and they arise out of frustration with the pace of CW standard development, along with a different view on the priority of various reliability gaps. Should this document provide guidance on whether it is appropriate for a regional standard to address a continent-wide issue just to~~

~~get it done faster[GVZ6]?]~~This endeavor should not preclude the region from addressing any reliability related need, especially in the event NERC lacks sufficient resources to develop the continent wide standard, or Interconnection wide standard.[HLG7]

When a region posts a proposed regional SAR for comment, they will send a notification of that posting to NERC staff. NERC will then send a notification of the posting to industry stakeholders informing them of the region's desire to obtain comments on the proposed regional SAR. (should the comment form have a question about whether the SAR should apply on a footprint larger than the region?) ~~The Regional Standards Group (RSG) could support posting proposals for new/revised requirements that may apply on less than a continent-wide basis and solicit continent-wide stakeholder feedback on the scope of the reliability related need for the new/revised requirements.~~ [HLG8][COMMENT: We would not support posting regional standards for continent-wide substantive feedback. As a single interconnection region, with a unique set of technical and market rules, we do not think soliciting comments from outside of the region would be helpful. Of course, anyone can submit comments during our regional posting periods[GVZ9].]

~~As envisioned, a proposal for new/revised requirements would be posted for an informal 30-day comment period with a webinar conducted during that comment period. The posting would consist of a 'Technical Concepts' paper that includes a description of the proposed new/revised requirements and a summary of the technical work done accompanied by a comment form. The comment form would, as a minimum, identify whether stakeholders agree that there is a need for a new/revised requirements; whether the requirements should apply on a regional, interconnection, or continent-wide basis; and whether stakeholders agree that the technical work done is sufficient, or believe additional work is needed before developing the requirements. NERC staff would assemble the comments and share them with both the RSG and the Standards Committee.~~ [HLG10][See above comment.]

Stopped here – November 28

If ~~stakeholders~~ it is determined that the proposed requirements should apply on a continent-wide basis and the technical justification already developed by the Region is applicable on a continent-wide basis, then the Region should work with the Standards Committee to identify a priority[GVZ11] for developing the standard before starting development of the Regional Standard[GVZ12].

- If the new standard is closing an identified gap in reliability, then it should [GVZ13]receive a high priority and development should start within a timeframe acceptable to the sponsoring Region.[HLG14]
- If the Standards Committee cannot commit to starting the project in a time frame acceptable to the sponsoring Region (either because the priority is not high enough or because there are already too many projects under active development) then the sponsoring Region should proceed with developing the standard as a Regional Standard.[HLG15] [COMMENT: This encourages a Region to move forward simply because the NERC process is too slow – other places in this document discourage such action.]
- The Standards Committee should make a commitment to use the work done in developing the Regional Standard as a starting point for developing the continent-wide standard. [HLG16] [COMMENT: I don't think the SC can make such a commitment. The CW SDT may have very different views from the regional SDT. See recent experience with the rapid development project.]

DRAFT

If the technical justification developed by the Region is applicable to a subset of the continent, and additional time is needed to determine if the requirements should apply on a continent-wide basis, the RSG should coordinate its actions [what role/authority does the RSG have in connection with this process?] with the Standards Committee before starting development of the Regional Standard.[HLG17]

- The Standards Committee should work with NERC's technical committees to develop the technical justification for the continent-wide requirements and report to the RSG [??] on the proposed timeline for development of any necessary technical justification.[HLG18]
- If the sponsoring Region needs enforceable requirements before a determination is made on whether the proposed requirements should apply on a continent-wide basis, then the Region should proceed with developing the standard as a Regional Standard.
- If a determination is made that the requirements should apply on a continent-wide basis, the Standards Committee should make a commitment to use the work done in developing the Regional Standard as a starting point for developing the continent-wide standard. [See above.]

If ~~stakeholders determine~~ the applicable authority determines that the proposed new/revised requirements are needed for reliability and should apply on less than a continent-wide basis and less than an Interconnection-wide basis, then the ~~RSG~~ NERC staff should work with the sponsoring Region to consider the best method of approaching development of that standard – as a variance to a continent-wide standard or as a regional standard. In making this determination, the ~~RSG~~ Region should consider FERC's differentiation between variances and regional standards.[HLG19]

- If new requirements address a topic not covered in a continent-wide standard, then the new requirements should be developed as a "Regional Standard" following the Regional Standards Development Process.
- If new requirements are more stringent or cover an aspect of a topic already addressed in a continent-wide standard, then the new requirements should be proposed as a Variance to the continent-wide standard. To initiate development of a Variance, the Region or entity wanting the Variance must submit the Variance, the technical justification for the Variance, and a SAR to the NERC Standard Process Manager. The ~~RSG~~ Region should work with the Standards Committee to identify a priority for developing the Variance. [COMMENT: This seems to assume that any Variance would be developed under a NERC process. That view improperly leaves out regional development of variances, which is covered by our FERC-approved regional process.]

If ~~stakeholders~~ the applicable authority determines that the proposed new/revised requirements are needed for reliability [HLG20]and should apply on an Interconnection-wide basis, and the Interconnection does not have a NERC approved single Regional Standards Development Process that is applicable to the entire Interconnection, then that Interconnection should develop the Interconnection-wide Variance using the continent-wide standard development process. (Submit the Variance, the technical justification for the Variance, and a SAR to the NERC Standard Processes Manager and then work with the Standards Committee to establish a priority for the project.)

If ~~stakeholders~~ the applicable authority determines that the proposed new/revised requirements are needed for reliability and [HLG21]should apply on an Interconnection-wide basis, and the Interconnection has a single NERC--approved Regional Standards Development Process, then that Interconnection should develop the Interconnection-wide Variance using its Standard Development Process.

DRAFT

If "new" requirements address an activity that is:	And the standard is:	And the standard applies to:	Then the standard belongs in:	With the standard developed following:
Addressed in continent-wide standard	More stringent than continent-wide requirement	An entire Interconnection	Interconnection-wide variance to continent-wide standard	SAR submitted through continent-wide process Not correct. This table needs work. Depends on whether interconnection is single-region, etc.
	Different method of achieving same reliability goal; difference necessary for physical difference or other reason	A Region, set of Regions, or a specific set of functional entities	Less than interconnection-wide variance to continent-wide standard	
Not addressed in continent-wide standard	Not needed for reliability on a continent-wide basis	A ~~n entire~~ multi-region Interconnection[HLG22]	Interconnection-wide standard	Interconnection-wide regional standard process (does such a thing exist?)
		A single Region	Regional Standard	Regional standard process
	Needed for reliability on a continent-wide basis	Entire continent	Continent-wide standard	Continent-wide standard process

DRAFT

Requesting a Variance to a Continent-wide Standard

The Standard Processes Manual clarifies that there are two types of variances – those that apply to an entire interconnection and those that apply to entities on a less than interconnection-wide basis.

When any request for a Variance to a continent-wide standard is submitted with a SAR, the request should include the following:

- A technical justification for the variance suitable for posting so that all stakeholders understand the need for the variance[HLG23]
- A statement indicating whether the proposed requirement is "in addition to" or "an alternative to" one or more specific requirements in the continent-wide standard
- For each requirement proposed, the associated Violation Risk Factor, Time Horizon, Measure, Evidence Retention, and set of Violation Severity Levels

Retiring or Revising Regional Standards to Avoid Duplication or Conflict with Continent-wide Standards:[HLG24]

When a continent-wide standard is developed and addresses the same topic as addressed in a Regional standard, an ~~joint~~ implementation plan that considers approved regional plans is needed to ensure stakeholders are not accountable for performance with two different requirements addressing the same performance at the same time.[HLG25]

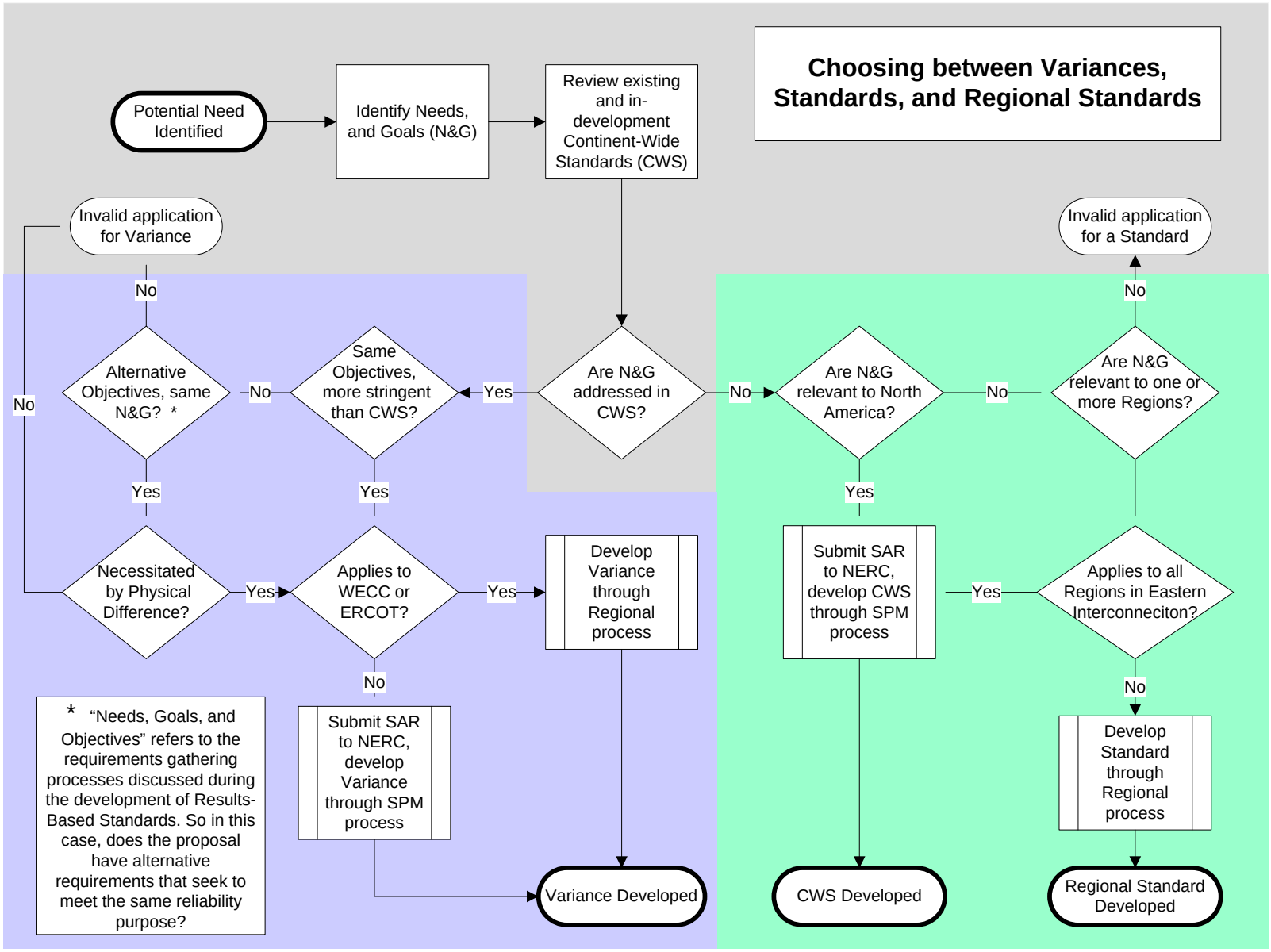
- If the performance in the Regional Standard is more stringent than the performance in the continent-wide standard, then the Regional Standard should be absorbed into the continent-wide standard with the more stringent requirements addressed either in a table (similar to the tables in INT-006-3) or as a variance to the continent-wide standard.[HLG26]
- If the continent-wide standard addresses some but not all of the performance in the Regional Standard, then on a case-by-case basis, the Region, working with the continent-wide drafting team, should determine what to do with the requirements that identify performance not included in the continent-wide standard. Acceptable choices include:
    - Revising the Regional Standard to remove only the requirements duplicated in the continent-wide standard;
    - Moving requirements that explain 'how' into a regional procedure, or
    - Adding requirements from the Regional Standard into the continent-wide standard in the form of a Regional Variance.[HLG27]
- If the performance in the Regional Standard is less stringent than the performance in the continent-wide standard, then the Regional Standard must be retired at the time that the continent-wide standard goes into effect.[HLG28]

Proposals:

1. The language in the Standard Processes Manual allows a broader range of variances than identified in the Rules of Procedure. The language in the Rules of Procedure should be modified to align more closely with the language in the SPM.[HLG29]

2. The Standards Committee should add criteria to its prioritization tool to encourage the development of variances as opposed to regional standards [As defined above, regional standards and variances are used in different circumstances; one should not be "encouraged" over the other.] and should give priority to these proposals to minimize the Regions' needs to develop Regional standards that will later be displaced by continent-wide standards addressing the same topic. [This seems to assume that variances will be developed by CW SDTs rather than on a regional basis. I'm not sure that is correct, especially for Texas and WECC.][HLG30]
3. The Regional Standards Group should seek stakeholder feedback on a continent-wide basis for all proposed regional standards at the project proposal stage. [Oppose.][HLG31]

DRAFT


Choosing between Variances, Standards, and Regional Standards
Potential Need Identified
Identify Needs, and Goals (N&G)
Review existing and in-development Continent-Wide Standards (CWS)
Are N&G addressed in CWS?
Yes
No
Same Objectives, more stringent than CWS?
Yes
No
Alternative Objectives, same N&G? *
Yes
No
Necessitated by Physical Difference?
Yes
Applies to WECC or ERCOT?
Yes
No
Develop Variance through Regional process
Submit SAR to NERC, develop Variance through SPM process
Variance Developed
Invalid application for Variance
* "Needs, Goals, and Objectives" refers to the requirements gathering processes discussed during the development of Results-Based Standards. So in this case, does the proposal have alternative requirements that seek to meet the same reliability purpose?
Are N&G relevant to North America?
Yes
No
Submit SAR to NERC, develop CWS through SPM process
CWS Developed
Are N&G relevant to one or more Regions?
Yes
No
Applies to all Regions in Eastern Interconneciton?
Yes
No
Develop Standard through Regional process
Regional Standard Developed
Invalid application for a Standard

From: david.kiguel@HydroOne.com
To: Lee R. Pedowicz
Subject: FW: NERC: Standards Committee - Preliminary Election Results | Initial Election November 8-18, 2011 | Segment 3
Date: Thursday, November 10, 2011 2:34:34 PM

Lee, this is the one to send.

From: Monica Benson [mailto:Monica.Benson@nerc.net]
Sent: Tuesday, November 08, 2011 4:22 PM
To: rbbs3
Subject: NERC: Standards Committee - Preliminary Election Results | Initial Election November 8-18, 2011 | Segment 3

Standards Committee

Preliminary Election Results
Initial Election November 8-18, 2011

The Standards Committee nomination period for the January 2012 through December 2013 two-year term has closed. Twenty-two nominations were received, including at least one for each of the ten Industry Segments.

Each of the ten Industry Segments must elect one representative. The following individuals were the only individuals nominated to represent their Industry Segment, and are elected to the Standards Committee as they were unopposed:

- Segment 2 – Ben Li
- Segment 4 – Allen Mosher
- Segment 7 – Frank McElvain
- Segment 9 – Klaus Lambeck

The following individual was elected through an alternative process ratified by members of that Industry Segment as allowed under the Election Procedure for Members of NERC Standards Committee:

- Segment 10 – Linda Campbell

In accordance with the Election Procedure for Members of NERC Standards Committee, an election will be held for Segments 1, 3, 5, and 8. For each of these segments, we received more than one nominee. The slate of nominees for each of these segments is shown below and detailed information on each of these candidates is posted on the Standards Committee's Nominations and Elections web page:

Segment 1:

- David Kiguel
- Carol Sedewitz

Segment 3:

- Wayne Amondson
- John Babik
- John Bussman
- John Hagen
- Michael DeLoach

- Linn Oelker
- Keith Porterfield

Segment 5:

- Randy Crissman
- Amir Y Hammad
- Scott Miller
- Don Mzyk
- John Seelke

Segment 6:

- Andrew Gallo
- Alice Ireland

Segment 8:

- Frederick R. Plett
- James Stanton

The election will begin on Tuesday, November 8, 2011 and remain open for ten calendar days. Each individual that is a member of the Registered Ballot Body in one of the Industry Segments identified above will vote for a Standards Committee member to represent that Industry Segment. Proxies are allowed.

Next Steps

To be elected during the initial ballot, a nominee must meet both of the following:

- Receive the highest total number of votes in that Segment, and
- Receive a simple majority of the votes cast in that Segment.

If no candidate meets both criteria through the initial ballot, a second ballot will be conducted in that Segment. For the second ballot, the slate consists of the two candidates who received the highest number of votes in the initial ballot.

The candidate receiving the highest number of votes in the second ballot is elected to represent that Segment.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Y

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Committee Announcement | 2012 - 2013 SC Initial Ballot Election Results
Date: Tuesday, November 22, 2011 2:05:37 PM

2012-2013
Standards Committee Elections

Initial Ballot Election Results for 2012-2013 Term

The initial ballot for the election of Standards Committee members in Segments 1, 3, 5, 6 and 8 closed on November 18, 2011. The results are shown below.

Election Criteria: To be elected during the initial ballot, a nominee must meet both of the following:

- Receive the highest total number of votes in that Segment, and
- Receive a simple majority of the votes cast in that Segment.

If no candidate meets both criteria through the initial ballot, a second ballot will be conducted in that Segment. For the second ballot, the slate consists of the two candidates who received the highest number of votes in the initial ballot.

In the second ballot, the candidate receiving the highest number of votes is elected to represent that Segment.

Election Results:

Segment 1 — The two candidates received an equal number of votes, thus neither candidate received a simple majority of votes and a second ballot will be conducted.

- Carol Sedewitz, National Grid
- David Kiguel, Hydro One Networks Inc.

Segment 3 — John Bussman, Associated Electric Cooperative Inc. received the highest total number of votes and a simple majority and has been elected.

Segment 5 — The two candidates who received the highest total number of votes are listed below; neither candidate received a simple majority of votes and a second ballot will be conducted.

- Amir Hammad, Constellation Power Source Generation
- Scott Miller, MEAG Power

Segment 6 — Alice Murdock, Xcel Energy received the highest total number of votes and a simple majority and has been elected.

Segment 8 — Frederick Plett, Massachusetts Attorney General, received the highest total number of votes and a simple majority and has been elected.

The following were previously elected to the Standards Committee for the 2012-2013 term, either by running unopposed or through an approved alternative process:

- Segment 2 – Ben Li, Independent Electric System Operator
- Segment 4 – Allen Mosher, American Public Power Association

- Segment 7 – Frank McElvain, Siemens Power Technologies International
- Segment 9 – Klaus Lambeck, Public Utilities Commission of Ohio
- Segment 10 – Linda Campbell, Florida Reliability Coordinating Council

Next Steps:

Runoff elections to select representatives to the Standards Committee for Segments 1 and 5 will be conducted from November 29 through December 8, 2011. Any member of the Registered Ballot Body in Segment 1 is eligible to vote in the runoff election for the Segment 1 representative, and any member of the Registered Ballot Body in Segment 5 is eligible to vote in the runoff election for the Segment 5 representative.
Instructions on voting for the runoff election will be sent next week.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1276722-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com

From: Monica Benson
To: monica.benson@nerc.net
Subject: Standards Committee - Segment 1 Runoff Election | November 29 – December 8, 2011
Date: Tuesday, November 29, 2011 9:54:22 AM

Standards Committee

Segment 1 Runoff Election
November 29 – December 8, 2011

To vote, click here: Segment 1 Voting Now Available

The Standards Committee initial election for the January 2012 through December 2013 two-year term has closed. To be elected during the initial ballot, a nominee must meet both of the following:

- Receive the highest total number of votes in that Segment, and
- Receive a simple majority of the votes cast in that Segment.

Both of the nominees in Segment 1 received an equal number of votes. Since neither of the nominees for Segment 1 received a simple majority of the votes cast in that segment, in accordance with the Standards Committee Election Procedure, a runoff election is being conducted between the two candidates, **David Kiguel and Carol Sedewitz**. Detailed information on each of these candidates is posted on the Standards Committee's Nominations and Elections webpage.

Instructions for Voting in the Runoff Election
Only members of Segment 1 of the Registered Ballot Body, or their proxies, are eligible to vote in the Segment 1 runoff election. Votes must be submitted electronically. To cast a vote, click here.

Next Steps
The candidate receiving the highest number of votes in the second ballot is elected to represent the Segment.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1277110-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com

From: Monica Benson
To: monica.benson@nerc.net
Subject: Standards Committee - Segment 5 Runoff Election | November 29 – December 8, 2011
Date: Tuesday, November 29, 2011 9:53:49 AM

Standards Committee

Segment 5 Runoff Election
November 29 – December 8, 2011

To vote click here: Segment 5 voting now available

The Standards Committee initial election for the January 2012 through December 2013 two-year term has closed. To be elected during the initial ballot, a nominee must meet both of the following:

- Receive the highest total number of votes in that Segment, and
- Receive a simple majority of the votes cast in that Segment.

None of the nominees for Segment 5 received a simple majority of the votes cast in that segment. In accordance with the Standards Committee Election Procedure, a runoff election is being conducted between the two candidates that received the highest number of votes in Segment 5, **Amir Hammad and Scott Miller**. Detailed information on each of these candidates is posted on the Standards Committee's Nominations and Elections webpage.

Instructions for Voting in the Runoff Election
Only members of Segment 5 of the Registered Ballot Body, or their proxies, are eligible to vote in the Segment 5 runoff election. Votes must be submitted electronically. To cast a vote, click here.

Next Steps
The candidate receiving the highest number of votes in the second ballot is elected to represent that Segment.

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1277122-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com

Standards Committee Election 2012-2013 Segment 1 Runoff

Segment 1 Runoff Election
November 29 â€“ December 8, 2011

The Standards Committee initial election for the January 2012 through December 2013 two-year term has closed. To be elected during the initial ballot, a nominee must meet both of the following:

- **Receive the highest total number of votes in that Segment, and**
- **Receive a simple majority of the votes cast in that Segment.**

Both of the nominees in Segment 1 received an equal number of votes. Since neither of the nominees for Segment 1 received a simple majority of the votes cast in that segment, in accordance with the Standards Committee Election Procedure, a runoff election is being conducted between the two candidates, David Kiguel and Carol Sedewitz. Detailed information on each of these candidates is posted on the Standards Committeeâ€™s Nominations and Elections web page.

Instructions for Voting in the Runoff Election
Only members of Segment 1 of the Registered Ballot Body, or their proxies, are eligible to vote in the Segment 1 runoff election. Votes must be submitted electronically.

Next Steps
The candidate receiving the highest number of votes in the second ballot is elected to represent the Segment.

Save and Quit Next >>

Powered by CHECKBOX® Survey Software - ©2007 Prezza Technologies, Inc.

From:	Ben Li Associates
To:	kgoodman@iso-ne.com; rscmembers; rjfalsetti@cogeco.ca; donald.e.nelson@state.ma.us; david.kiguel@HydroOne.com
Subject:	RE: NERC SC Teleconference November 10, 2011
Date:	Tuesday, November 15, 2011 4:20:27 AM

Kathleen, thanks.

The SC met with a number of SDT chairs/vice-chairs at the October face to face meeting and got feedback that in general, the QR process added value to standards development. The extended delays caused by the QR process were not mentioned at that meeting.

That said, I am not ruling out that there have been delays that could result in project slippages. I will raise this with the SC at the next meeting.

Ben

From: Goodman, Kathleen [mailto:kgoodman@iso-ne.com]
Sent: Monday, November 14, 2011 5:31 PM
To: rscmembers@npcc.org; rjfalsetti@cogeco.ca; donald.e.nelson@state.ma.us; Ben Li Associates; david.kiguel@HydroOne.com
Subject: FW: NERC SC Teleconference November 10, 2011

All – I was under the impression that the QR process was supposed to help the standards? Based on these notes and Brian's assertion re the QR comments, I think it is time to revisit. Ben and David – do you think you can bring up at a future SC meeting?

From: david.kiguel@HydroOne.com [mailto:david.kiguel@HydroOne.com]
Sent: Friday, November 11, 2011 4:17 PM
To: rscmembers@npcc.org; rjfalsetti@cogeco.ca; donald.e.nelson@state.ma.us; ben@benli.ca
Subject: NERC SC Teleconference November 10, 2011

Hello all,

My notes of the SC Teleconference are attached.

David

This email and any of its attachments may contain information that is privileged, confidential, classified as CEII, or subject to copyright belonging to NPCC. This email is intended solely for the use of the individual or entity to which it is addressed. If you are not the intended recipient of this email, you are hereby notified that any dissemination, distribution, copying, or action taken in relation to the contents of and attachments to this email is strictly prohibited and may be unlawful. If you receive this email in error, please notify the sender immediately and permanently delete the original and any copy of this email and any printout.

Agenda
Standards Committee Meeting

November 10, 2011 | 1-5 p.m. Eastern
Phone Number: 1-866-740-1260
Meeting Code: 4685998
Security Code: 224466

Introductions and Chair's Remarks
NERC Antitrust Compliance Guidelines and Public Announcement*
Agenda

1. **Review of Agenda (Approve)**
   Quorum obtained.
   Approved.
2. **Waiver of 5-day Rule (Approve)**
   Approved
3. **Consent Agenda (Approve)**
   a. October 3, 2011 Standards Committee QRAWG Meeting Minutes* (Ratify) b.

   October 10, 2011 Standards Committee QRAWG Meeting Minutes* (Ratify) c.

   October 12, 2011 Standards Committee Meeting Minutes*

   d. October 20, 2011 Standards Committee QRAWG Meeting Minutes* **(Ratify)**
   e. October 24, 2011 Standards Committee Executive Committee Meeting Minutes***(Ratify)**
   f. November 2, 2011 Standards Committee QRAWG Meeting Minutes* **(Ratify)**
   g. Project 2010-07 — Generator Requirements at the Transmission Interface Standard Drafting Team * **(Appoint) Confidential (To be sent separately)**

   Approved for3a hrough 3f. Item 3g moved out.
   3gi: Two candidates proposed.
   Approved.
4. **High Priority Projects, Activities, and Action Items (Review)**
   a. Status of Projects Identified as High Priority* (A. Rodriquez)

One Project Completed:

- *Project 2006-02 Assess Transmission Future Needs. Note this project may be impacted by future actions regarding the TPL Footnote B project, currently proposed for Remand by the FERC.*

Six Projects on Schedule (+/- Two Weeks):

- *NEW Project 2007-06 System Protection Coordination*
- *Project 2007-12 Frequency Response*
- *Project 2007-17 Protection System Maintenance and Testing*
- *Project 2008-06 Cyber Security Order 706*

- *Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves. This projects schedule is being redeveloped based on feedback from the last Standards Committee meeting.*
- *Project 2010-17 Definition of BES*

One Project Ahead of Schedule:

- *NEW Project 2010-07 Generator Requirements at the Transmission Interface*

Seven Projects Behind Schedule:

Analysis of timelines and delays are based on schedules adjusted and presented at the July SC meeting.

- *NEW Project 2006-06 Reliability Coordination. This project is approximately 3 months behind schedule. Recently, its schedule has slipped due to more time being required to respond to comments received during Quality Review than expected. Originally expected to take 2 weeks, it actually has taken the team 14 weeks so far.**
- *Project 2007-02 Operating Personnel Communication Protocols. This project is approximately 4 months behind schedule. Recently, its schedule has slipped due to the team focusing on completing the related interpretation. Quality issues have also been identified that are being addressed. Their original target was to complete the draft of the standard over four weeks, but it actually has taken the team 17 weeks so far.**
- *Project 2007-03: Real-time Operations - The work done in response to the most recent Quality Review took longer than anticipated – approximately 4 weeks longer than planned. QRAWG review and subsequent modification has taken an additional 3 weeks.*
- *Project 2007-07 Vegetation Management. This project has completed its recirculation ballot, and is being presented to the Board of Trustees on November 3. An update on its status will be provided verbally. Its delay was caused first by its coordinator leaving NERC, then primarily by moving to informal development, both periods during which the SDT worked independently. This resulted in modifying the standard in response to comment staking a significant amount of time longer than planned (slightly more than one year in total from the Initial ballot to the submission for Recirculation)*
- *NEW Project 2007-09 Generator Verification. This project is approximately 1.5 months behind schedule. Recently, its schedule has slipped due to more time being required to respond to industry comments than expected. Originally expected to take 5 weeks, it actually has taken the team 12 weeks so far.**
- *NEW Project 2009-01 Disturbance and Sabotage Reporting. This project is approximately 2.5 months behind schedule. Recently, its schedule has slipped due to resource conflicts, resulting in delays related to submitting documents to QR and responding to QR's feedback. Originally expected to take 2 weeks, it actually took the team 10 weeks.**
- *NEW Project 2010-05.1 Phase 1 of Protection Systems: Misoperations. This project is approximately 7.5 months behind the desired schedule due to confusion regarding the projects goals. The team is reevaluating its project schedule to accelerate the project.*

b. Status of Outstanding Interpretations *(L. Hussey and A. Rodriquez)

No new interpretations received since last SC meeting.

Project	*Status*

Project 2008-10 — Interpretation of CIP-006-1 for Progress Energy	*Posted for parallel comment and successive ballot through November 21, 2011.*
Project 2009-22 — Interpretation of COM-002-2 for the IRC	*Posted for parallel comment period and initial ballot through November 17, 2011.*
Project 2009-26 — Interpretation of CIP-004-1 for WECC	
Project 2010-INT-05 CIP-002-1 for Duke Energy	*In progress*
2010-INT-01 TOP-006-2 for FMPP	*Awaiting outcome of CAN discussion at November 2011 BOT meeting.*
2010-INT-02 TOP-003-1 for FMPP	*Awaiting outcome of CAN discussion at November 2011 BOT meeting.*
Project 2010-INT-03 TOP-002-2a for FMPP	*Awaiting outcome of CAN discussion at November 2011 BOT meeting.*
RFI received on 11/4/2010 from TECO on CIP-007	*Requester has indicated that he would like to move forward with the request, pending the outcome of revisions to CAN.*
RFI received in 12/9/2010 from Bridgeport Energy on FAC-008-1	*CAN-0018 on this issue was posted as final 6-17-11. Requester has been contacted to see if the CAN satisfies their need for clarification. Awaiting response. Note: due to the BOT's request that all CANs be rewritten, requester will need to be contacted when CAN-0018 is revised.*
RFI received on 12/28/2010 from ITC on CIP-007	*Assigned to CIP IDT, to be processed when earlier requests have been moved through the process.*
RFI received on 1/28/2011 from Constellation Power Gen on VAR-002-1b	*Accepted for processing.*
RFI received on 2/24/2011 from OGE on CIP-002-3 R1.2.5	*Assigned to CIP IDT, to be processed when earlier requests have been moved through the process.*
RFI received on 5/13/11 from FPL on MOD-028-1	*Revision to the standard is posted for parallel comment and initial ballot through November 16, 2011.*
RFI received on 6/9/2011 from Consumers Energy on CIP-003-3	*Assigned to CIP IDT, to be processed when earlier requests have been moved through the process.*
RFI received on 7/22/11 from EEI and NRECA on CIP-001-1	*In August the SC voted to move forward with this interpretation. Drafting team appointment on hold pending finalization of CAN-0016 to see if the revision of the CAN provides clarification. In September, the SC reaffirmed this decision. In October, EEI indicated their intent (in policy input to the Board of Trustees) to pursue an appeal of CAN-0016.*

5. **Standard Actions**

   a. Project 2007-17 - Protection System Maintenance & Testing - PRC-005* (A. Rodriquez) **(Appoint)**

Confidential (To be sent separately)

Removing 2 inactive members and adding 8 new members.

No NPCC reps in initial slate. Carol proposed to add one. Long discussion. Final motion without the NPCC rep.
Approved.
Additional NPCC person will be sought in a couple of month if the SDT Chair concurs.

6. **Reports**
   a. Report from Board of Trustees and Standards Oversight and Board of Trustees Meetings (A. Mosher and H. Schrayshuen)

   BoT approved the VM standard and the reliability standards development plan (RSDP).

b. Report from Order 754 Tech Conference (H. Schrayshuen) *Moved to 4ai*

c. Report on Throughput Issues (H. Schrayshuen)

7. **Coordination (Review)**
   a. Coordination with Regulatory and Governmental Authorities (H. Hawkins)
   b. Coordination with Regional Managers (H. Schrayshuen)
   c. Update on Proposal for Coordination with Regional Standards Development* (M. Long)
8. **Discussion Items**
   a. Report from October 13 Strategic Planning Session* (M. Gildea)
   Send comments to Allen by the 17th.

b. Project 2010-07 – Generator Requirements at the Transmission Interface – Impact of Compliance Process Directive #2011-CAG-001* (P. Brown)
Concerns that directive circumvents the established standards development process.
Appears to be expanding the requirements.

9. **Informational Items (Review)**
   a. Drafting Team Vacancies*
   b. Standards Committee Roster*
10. **Executive Committee Actions (Pre-authorize)**
   a. Project 2010-05.1 Phase 1 of Protection Systems: Misoperations – Project schedule* **(Endorse)**
   This project involves two phases, with the initial phase focused solely on standard related to misoperations. This project is a "pilot" for the "rapid development" process and, when started, had a target project duration (from SAR posting to completion of the recirculation ballot) of 12 months. The team submitted a project schedule that proposed a project duration of 18 months. When reviewed during the October 2011 Standards Committee meeting, the committee expressed concern that the schedule did not reflect the goals associated with piloting the rapid development process. The committee directed the team to develop a schedule that supports the rapid development goals.
   This project team has not met to review changes to the schedule, but has virtual meetings scheduled in November and is expected to produce a revised schedule for Standards Committee review and endorsement before the December Standards Committee meeting.

Agreed to give SC Executive Committee authority to decide.

b. Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves – Project schedule* **(Endorse)**

This project involves two phases, with several standards in each of the phases. Some of the standards involved in Phase 1 have been posted for stakeholder comment and some have not.
The team submitted a single project schedule that proposed posting all standards in this phase of the project for an initial and a recirculation ballot and seemed to assume that the standards already vetted as well as the new standards that haven't been posted for any stakeholder review, would all receive sufficient stakeholder support to move forward with an initial and a recirculation ballot. When reviewed during the October 2011 Standards Committee meeting, the committee expressed concern that the schedule, for those standards that haven't already been posted for at least one formal comment period, is not realistic. The committee endorsed the proposed schedule for those standards that have already been posted for stakeholder comment and directed the drafting team to develop a more realistic schedule for its proposed standards that have not been posted.
An updated schedule based on the Standards Committee's guidance has been drafted and is being reviewed internally prior to moving forward before the December Standards Committee meeting.

11. **Adjourn**

From: Jordan Erwin
To: canonly
Subject: NERC Announcement: Activity on the Compliance Application Notice (CAN) Website
Date: Tuesday, November 22, 2011 2:24:09 PM

NERC Compliance Announcement:

DRAFT CAN Posted for Industry Review

DRAFT CAN Industry Comment Materials Posted

Updated CAN Status Spreadsheet

The following draft CAN has been posted on the NERC Web site for industry review:

- **DRAFT CAN-0027**: TOP-003 R2 Coordination of Scheduled Outages
  This CAN will be posted for industry comment until **December 14, 2011**. Please email comments using the CAN Comment Form to cancomments@nerc.net.

The following DRAFT CAN Industry Comment materials are posted on the NERC Web site:

- **DRAFT CAN-0030**: Attestations
  - Comment Analysis Summary
  - Industry Comment Analysis Spreadsheet
  - Industry Comments Received

The CAN Status spreadsheet has been posted as final under the Complete List of CANs and Status section on the NERC Web site:

- The CAN Status spreadsheet has been updated to reflect the recent changes to Compliance Application Notices. This spreadsheet indicates where each CAN currently resides in the CAN development process.

For more information regarding Compliance Application Notices, please contact Valerie Agnew at (404) 446-2566, Ben Engelby at (404) 446-2578 or Caroline Clouse at (404) 446-2588.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Y

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

November 10, 2011

Mr. Michael Moon
Director of Compliance Operations
North American Electric Reliability Corporation
3353 Peachtree Road NE
Atlanta Financial Center-North Tower
Suite 600-Sixth Floor
Atlanta, Georgia 30326

Re: Request for Clarification on Compliance Application Notice 0006: EOP-005-1, Requirement 7, "Verification of Restoration"

Dear Mr. Moon:

The NPCC Restoration Working Group is charged to facilitate effective and coordinated power system restoration among the NPCC Reliability Coordinator areas and with adjacent jurisdictions. As part of its efforts, the Working Group annually reviews the restoration plans of the NPCC Reliability Coordinator areas, and it develops and leads an annual wide area restoration simulation with the Reliability Coordinators of NPCC and their neighboring Reliability Coordinators. Recognizing these responsibilities, the Restoration Working Group is seeking further clarification of Compliance Application Notice 0006: EOP-005-1, Requirement 7, "Verification of Restoration," regarding concerns raised previously.

The CAN broadly addresses restoration simulations as follows:

> "Regarding simulation: Simulation is an option that the TOP or BA can use to verify its restoration procedure. Simulation can include electronic simulation, which is a simulation of what is expected to actually occur during system restoration. Simulations may be conducted at a control center using the system operator's workstation or other facilities. Simulation can also include a walk-through simulation of a restoration procedure that has been tested using previous electronic simulation methods. In both cases, a CEA is to verify that the restoration scope and the results of the simulation are close enough to what would actually occur that decisions made during the simulation would be effective in actual restoration."

This describes the restoration exercises which are typically conducted throughout North America and certainly reflects the understanding of NPCC in applying Requirement 7. However, the CAN goes on to state:

> A ***simulated restoration exercise that takes place without actual equipment***[4] (whether by electronic or walk-through simulation) would not normally be considered verification "by actual testing or simulation," as required by the standard. However, under certain circumstances, a registered entity may fulfill the requirement by conducting a simulation restoration exercise(s) that takes place without actual equipment. For

a walk-through simulation conducted without actual equipment, the CEA is instructed to verify that the registered entity has a letter from either its BA or a TOP whose restoration procedure includes the registered entity, stating that:

1. the registered entity does not have a technical component to its restoration plan and

2. the registered entity's restoration is included in the BA's or TOP's restoration plan.

This statement does not provide any clarity to Requirement 7, which is already applicable to the BA and TOP. It is not clear what is meant by "…letter from either its BA or a TOP…" when the responsible entity is already a BA or TOP. It is the belief of the NPCC Restoration Working Group that this section of the CAN should be deleted since it has no relevance to the TOP or BA compliance requirements.

In addition, there is some doubt regarding how to demonstrate compliance as summarized in the CAN, revisions are suggested:

"Providing Evidence of Compliance

CEAs may use any of the following to obtain reasonable assurance of the entity's compliance:

- engineering analytical methods and practices;
- power flows to verify steady state conditions;
- transient stability analysis to verify the dynamic performance;
- electromagnetic transient analysis to verify switching operations.

CEAs are to verify that all of the evidence replicates actual events."

The language of the CAN infers that information in ALL of the bullets is necessary to achieve compliance. However, it is the belief of the NPCC Restoration Working Group that not all of the study work enumerated above is necessary to demonstrate evidence of compliance, and the CAN should be clearer on the point. Specific compliance measurements are being added outside of the Standard.

The CAN is introducing a limited definition for simulation that has not been vetted through the Standards Development Process. The term simulation is an undefined term and should be left with the registered entity to determine the appropriate level of simulation to meet the requirement. Lack of any or all of the four proposed means of simulation should not be a cause to find non-compliance. It may be appropriate to report to the area that this should be considered an area for improvement. If the industry or NERC believes it is necessary to define simulation for purposes of EOP-005, a SAR should be introduced to ensure the industry expert have an opportunity to develop the definition to improve the standard.

Your assistance in this important effort is appreciated.

Very truly yours,

David Dolan

David Dolan
Chair, NPCC Restoration Working Group (CO-11)

JGM:cd

cc: Members, NPCC Restoration Working Group (CO-11)
Members, NPCC Task Force on Coordination of Operation
Members, NPCC Regional Standards Committee
Members, NPCC Compliance Committee

From:	John G. Mosier Jr.
To:	Guy V. Zito; Lee R. Pedowicz
Subject:	FW: Request for Clarification on Compliance Application Notice 0006
Date:	Friday, November 11, 2011 7:55:16 AM
Attachments:	20111010_DD-MM_Request_for_Clarification_on_CAN_0006.doc

FYI

Thanks,

Jerry

From: Michael Moon [mailto:Michael.Moon@nerc.net]
Sent: Thursday, November 10, 2011 7:31 PM
To: John G. Mosier Jr.; Valerie Agnew
Subject: FW: Request for Clarification on Compliance Application Notice 0006

Val, please see below and prepare a response.

Thx m

From: John G. Mosier Jr. [mailto:jmosier@npcc.org]
Sent: Thursday, November 10, 2011 6:10 PM
To: Michael Moon
Cc: co11; tfco-all; rsc-members; cc-npcc
Subject: Request for Clarification on Compliance Application Notice 0006



NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

November 10, 2011

Mr. Michael Moon
Director of Compliance Operations
North American Electric Reliability Corporation
3353 Peachtree Road NE
Atlanta Financial Center-North Tower
Suite 600-Sixth Floor
Atlanta, Georgia 30326

Re: Request for Clarification on Compliance Application Notice 0006: EOP-005-1, Requirement 7, "Verification of Restoration"

Dear Mr. Moon:

The NPCC Restoration Working Group is charged to facilitate effective and coordinated power system restoration among the NPCC Reliability Coordinator areas and with adjacent jurisdictions. As part of its efforts, the Working Group annually reviews the restoration plans of the NPCC Reliability Coordinator areas, and it develops and leads an annual wide area restoration simulation with the Reliability Coordinators of NPCC and their neighboring Reliability Coordinators. Recognizing these responsibilities, the Restoration Working Group is seeking further clarification of Compliance Application Notice 0006: EOP-005-1, Requirement 7, "Verification of Restoration," regarding concerns raised previously.

The CAN broadly addresses restoration simulations as follows:

> "Regarding simulation: Simulation is an option that the TOP or BA can use to verify its restoration procedure. Simulation can include electronic simulation, which is a simulation of what is expected to actually occur during system restoration. Simulations may be conducted at a control center using the system operator's workstation or other facilities. Simulation can also include a walk-through simulation of a restoration procedure that has been tested using previous electronic simulation methods. In both cases, a CEA is to verify that the restoration scope and the results of the simulation are close enough to what would actually occur that decisions made during the simulation would be effective in actual restoration."

This describes the restoration exercises which are typically conducted throughout North America and certainly reflects the understanding of NPCC in applying Requirement 7. However, the CAN goes on to state:

> A ***simulated restoration exercise that takes place without actual equipment***[4] (whether by electronic or walk-through simulation) would not normally be considered verification "by actual testing or simulation," as required by the standard. However, under certain circumstances, a registered entity may fulfill the requirement by conducting a simulation restoration exercise(s) that takes place without actual equipment. For a walk-through simulation conducted without actual equipment, the CEA is instructed to verify that the registered entity has a letter from either its BA or a TOP whose restoration procedure includes the registered entity, stating that:
> 1. the registered entity does not have a technical component to its restoration plan and
>
> 2. the registered entity's restoration is included in the BA's or TOP's restoration plan.

This statement does not provide any clarity to Requirement 7, which is already applicable to the BA and TOP. It is not clear what is meant by "…letter from either its BA or a TOP…" when the responsible entity is already a BA or TOP. It is the belief of the NPCC Restoration Working Group that this section of the CAN should be deleted since it has no relevance to the TOP or BA compliance requirements.

In addition, there is some doubt regarding how to demonstrate compliance as summarized in the CAN, revisions are suggested:

> **"Providing Evidence of Compliance**
>
> CEAs may use any of the following to obtain reasonable assurance of the entity's compliance:
>
> - engineering analytical methods and practices;
> - power flows to verify steady state conditions;
> - transient stability analysis to verify the dynamic performance;
> - electromagnetic transient analysis to verify switching operations.

CEAs are to verify that all of the evidence replicates actual events."

The language of the CAN infers that information in ALL of the bullets is necessary to achieve compliance. However, it is the belief of the NPCC Restoration Working Group that not all of the study work enumerated above is necessary to demonstrate evidence of compliance, and the CAN should be clearer on the point. Specific compliance measurements are being added outside of the Standard.

The CAN is introducing a limited definition for simulation that has not been vetted through the Standards Development Process. The term simulation is an undefined term and should be left with the registered entity to determine the appropriate level of simulation to meet the requirement. Lack of any or all of the four proposed means of simulation should not be a cause to find non-compliance. It may be appropriate to report to the area that this should be considered an area for improvement. If the industry or NERC believes it is necessary to define simulation for purposes of EOP-005, a SAR should be introduced to ensure the industry expert have an opportunity to develop the definition to improve the standard.

Your assistance in this important effort is appreciated.

Very truly yours,

David Dolan

David Dolan
Chair, NPCC Restoration
Working Group (CO-11)

JGM:cd

cc: Members, NPCC Restoration Working Group (CO-11)
Members, NPCC Task Force on Coordination of Operation
Members, NPCC Regional Standards Committee
Members, NPCC Compliance Committee

From: Jordan Erwin
To: canonly
Subject: NERC Announcement: Activity on the Compliance Application Notice (CAN) Website
Date: Friday, November 11, 2011 4:10:51 PM

NERC Compliance Announcement:

Final Compliance Application Notices (CANs) Posted

- **Industry Comment Analysis Spreadsheet**
- **Comment Analysis Summary**
- **Industry Comments Redline**

DRAFT CANs Comment Analysis Posted

- **Industry Comment Analysis Spreadsheet**
- **Comment Analysis Summary**

Updated CAN Status Spreadsheet

New Category "Post Comment Period" on CAN website

New Document Type "Comment Analysis Summary" on CAN website

The following NERC CANs have been posted as final on the NERC website:

1. **CAN-0006**: EOP-005 R7 Verification of Restoration Procedure (Revised)
   - Final Version
   - Industry Comment Analysis Spreadsheet
   - Comment Analysis Summary
   - Industry Comment Redline

2. **CAN-0009**: FAC-008 and FAC-009 Facility Rating and Design Specifications (Revised)
   - Final Version
   - Industry Comment Analysis Spreadsheet
   - Comment Analysis Summary
   - Industry Comment Redline

3. **CAN-0017**: CIP-007 R5 Technical and Procedural System Access and Password Controls
   - Final Version
   - Industry Comment Analysis Spreadsheet
   - Comment Analysis Summary
   - Industry Comment Redline
4. **CAN-0018**: FAC-008 R1.2.1 Terminal Equipment (Revised)
   - Final Version

- Industry Comment Analysis Spreadsheet
- Comment Analysis Summary
- Industry Comment Redline

The following DRAFT NERC CANs have been analyzed, and the Industry Comment Analysis Spreadsheet and Comment Analysis Summary are posted on the NERC website:

1. **DRAFT CAN-0029**: PRC-004 R1, R2 and R3 Protection System Misoperations
   - Industry Comment Analysis Spreadsheet
   - Comment Analysis Summary
2. **DRAFT CAN-0039**: EOP-004-1 Filing DOE Form OE-417 Event Reports
   - Industry Comment Analysis Spreadsheet
   - Comment Analysis Summary

The updated NERC CAN Status spreadsheet has been posted as final under Complete List of CANs and Status section on the NERC website:

1. The CAN Status spreadsheet has been updated to reflect the recent changes to Compliance Application Notices. This spreadsheet indicates the status of each CAN currently in the development process. This list includes new potential CANs that have not been issued a priority.

The following additional category has been added to the NERC CAN website:

1. Category: "Post Comment Period" contains CANs that were posted for industry comment, the comment period has closed, and the comments are currently being reviewed by NERC staff. NERC received requests from industry to keep all CANs posted on the NERC website, so this tab was added to keep track of CANs after the comment period has closed.

The following new document type has been added to the NERC CAN website:

1. Document Type: "Comment Analysis Summary" is an overview of the industry comments received. This summary identifies the registered entities that submitted comments and provides rationale for why the CAN either changed or did not change based on the most prevalent comments. This document is intended to be supplemental information to provide further transparency into the CAN process.

Please email comments using the CAN Comment Form to cancomments@nerc.net.

For more information regarding Compliance Application Notices, please contact Valerie Agnew at (404) 446-2566, Ben Engelby at (404) 446-2578 or Caroline Clouse at (404) 446-2588.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com



- - -
Y

CAN Number (If a CAN has been numbered, it is under development)	CAN Requestor	Status	Standard	Project Subject	Item Description/Driver for Request (NERC has tried to identify these issues without identifying regions or registered entities; the description is a summary at the time of quarterly prioritization. It may not include all the related information currently identified with each possible CAN; NERC will document other information related to each within that CANs development history. Items listed here may require more than one CAN per standard or a group of similar issues into one CAN, depending on efficiencies, other NERC-wide efforts, etc.)	last updated: 11/22/11
5		Industry Comments/ Industry Redline	CIP-002-3 R3	Laptops remotely controlling BES assets are designated CCA	Registered entities and Regional Entities requested clarity regarding whether system operator laptops with the capability and purpose of controlling Bulk Electric System assets remotely (whether in normal operations or in emergencies) should be designated as Critical Cyber Assets (CCAs).	
6		Final	EOP-005-1 R7	Verification of Restoration Procedure by Actual Testing or by Simulation	This CAN provides instruction for assessing whether: 1) an entity has verified its restoration procedure "by actual testing or by simulation," as required by EOP-005-1 R7, and 2) the use of a third-party vendor impacts a registered entity's obligation under the standard	
7		Industry Comments/ Industry Redline	CIP-004-2 R4.2 CIP-004-3 R4.2	Revocation of Access (physical and electronic) to Critical Cyber Assets	Registered Entities and Regional Entities requested clarity about the extent and timing of revocation of access to Critical Cyber Assets (CCAs) required in CIP-004 R4.2. Specifically, clarity was sought on what constitutes revocation, access (physical and electronic), and what constitutes revocation of access to CCAs under different entity-specific scenarios.	
8		Final	PRC-005-1 R2	Pre-June 18 evidence	NERC Compliance received a request for clarification on PRC-005-1 R2 regarding the monitored timeframes for gathering evidence pre-June 2007 when determining compliance with an entity's maintenance and testing program. What is the validity of a regional auditor to ask for evidence pre June 2007 even though there was no obligation to retain records until at least June 17, 2007?	
9		Final	FAC-008 R1 FAC-009 R1, R2	Facilities not Matching Design Specifications	This CAN provides instruction for assessing compliance with FAC-008 R1 and FAC-009 R1 when an entity's constructed Facilities do not match its design specifications.	
10		Final	Definition of "Annual"	Definition of "Annual"	The definition of "annual" and implementation of annual requirements	
11		Final	PRC-005-1 R2	New Equipment	NERC Compliance received a request for clarification on PRC-005-1 R2 regarding gathering evidence of initial testing for new equipment	
12		Final	Requirement of periodic action by Effective Date	Requirement of periodic action by Effective Date	Registered entities and Regional Entities have requested that NERC provide clarification on whether a registered entity must provide evidence that it completed a periodic action or event required by a NERC Reliability Standard (Standard) prior to the registered entity's Effective Date for the Standard.	
13		Final	PRC-023	R1 and R2	This CAN clarifies the Effective Dates for SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, under PRC-023 Requirement (R) 1 and R2.	
15		Industry Comments/ Industry Redline	EOP-002-2 Attachment 1; EOP-005-1 R11.3; IRO-002-2 R4, R5, R6; IRO-003-2 R1, R2; IRO-005-3 R1; and IRO-006-4.1 R1.4.1	NERC Tools	NERC Compliance received a request for clarification on a suite of reliability standards that require the use of a NERC tool. What is a registered entity's performance obligation to a standard's requirements when a NERC Tool is unavailable? EOP-005-1 R11.3: NERC Compliance received a request for clarification regarding "working with" and the applicability.	
16		Final	CIP-001 R1	Non-BES Facilities	Is a registered entity required to include non-BES facilities in its Sabotage Reporting Procedure?	

17		Final	CIP-007-3 R5	Password controls	Is a CEA is to verify that technical controls, procedural controls, or both are implemented in assessing compliance with CIP-007 Requirement (R) 5?	
18		Final	FAC-008 R1.2.1	1.2.1	This CAN provides instruction for assessing what equipment should be considered "terminal equipment" under FAC-008.	
19		In Development	CIP-007-3 R3	Security Patches	Is a registered entity required to have a technical control for password configuration or would a manual solution meet the requirement? How would a manual solution be audited? NERC Compliance received a request for clarification for when and under what conditions a TFE is required.	
20		Industry Comments/ Industry Redline	TPL-002a R6 & R11 TPL-002.0b R1.3.12 TPL-003a R1.3.12 TPL-004 R	Eval of Maintenance Outages	NERC received a request for clarification of whether maintenance outages, including Protection Systems, must be included in operational planning studies under TOP-002 or in transmission planning assessments under TPL-002, TPL-003, and TPL-004.	
21		In Development	COM-002	Definition of a Directive	NERC received a request for clarification of the definition of a "directive," whether it applies to both non-emergency and emergency situations, and the required use of three-part communications.	
22		Industry Comments/ Industry Redline	VAR-002-1.1b R1	Startup in Manual Mode	NERC received requests for clarification regarding whether a generator may be operated in manual mode during start-up.	
23		In Development	CIP-005 R3 CIP-006 R6 CIP-007 R6	Logging System Failures	NERC received a request for clarification of whether any exception exists for an entity that cannot log access 100% of the time, 24 hours per day, seven days per week, and if not, whether the entity needs to file a self-report of non-compliance any time the access logging system fails.	
24		Industry Comments/ Industry Redline	CIP-002-1 R3.1	Data Diodes	NERC received a request for clarification of whether the communication characteristics of data diode devices can be used to exclude non-critical Cyber Assets (CA) from consideration as Critical Cyber Assets (CCA) when a routable protocol is implemented, thereby making them inapplicable to CIP Standards.	
25		In Development	EOP-001-1 R2.4	BA Restoration Plans	NERC received the following question: When a BA is not a registered TOP, how does it comply with EOP-001-0 R3.4 (U.S.) or EOP-001-1 R2.4 (Canada), which require BAs to have a set of plans for system restoration?	
26		Industry Comments/ Industry Redline	TOP-006-1 R3	Protective Relays	NERC received a request for clarification of whether a RC, TOP and BA, under TOP-006 Requirement (R) 3, needs to provide appropriate technical information to its operating staff for all protective relays in its area whether or not it has the responsibility or ownership of the protective relays.	
27		Industry Comments/ Industry Redline	TOP-003-1 R2	Generator Outages	NERC received a request to clarify whether TOP-003 R2 requires the BA to plan and coordinate scheduled outages of generators within the BA's area.	
28		Final	TOP-006-1 R1.2	BA v. TOP Reporting	This CAN provides instruction for assessing whether a BA or TOP has fulfilled the requirements for reporting transmission or generation resources available for use to RCs and other affected BAs and TOPs under TOP-006 R1.2.	
29		Industry Comments/ Industry Redline	PRC-004-1 R2 R3	Misoperations	NERC received a request for clarification regarding whether entities must develop and implement Corrective Action Plans (CAPs) for, and maintain a record of, all Misoperations or only those that must be reported to NERC/RAPA.	
30		Gov't Regulators Comment Period	Attestations	Attestations	NERC received a request for clarification regarding the appropriate situations and uses of attestations as evidence of compliance with a reliability standard.	
31		Industry Comments/ Industry Redline	CIP-005 CIP-006 CIP-006 R1.1	Physical Security Access Points	NERC received a request to define the entry point metric definition of the access points on the perimeter. NERC also received a request for clarification for an acceptable entry point into a Physical Security Perimeter (PSP) of Critical Cyber Assets (CCA), as well as acceptable opening dimensions.	
32		In Development	EOP-008	Above and Beyond Security Measures	NERC received a request for clarification regarding whether an entity will be considered non-compliant if the measures it has implemented to comply with the requirement(s) of a Standard 1. meet the intent of the Standard and 2. exceed or are superior to the requirement of the Standard, 3. but do not meet the actual requirements of a given Standard.	

33		In Development	PRC-023 R1.8; • R1.9 • (R1.1; R1.6; R1.7)	Load questions	NERC Compliance received a request for clarity on: -"load remote to system" - "generation remote to load" - if there is a 4-hour load rating or can a seasonal facility rating be used for R1.1 -in a Directional Comparison Blocking (DCB) Scheme, does the reverse looking zone need to comply with PRC-23 loadability requirements? -R2 of the PRC-023-1 standard has an effective date of July 1, 2010 and if an entity chooses to apply R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13, how can this be a valid choice until they have the appropriate agreement from it PC, TOP and RC? -what is the process that requires every entity that falls under this standard to be included with unknown PA/PC in their respective regions? Some registered entities do not know who, if anybody, is their PA/PC., and upon contacting some TOPs, BAs, etc. in their area that are registered as a PA/PC to ask if they would serve as their PA/PC and were rebuffed. -the use of PC for PA and IC or IA in NERC Reliability Standards until a FERC Filing/Order is in effect.	
34		In Development	EOP-002-2.1 R1 IRO-001-1.1 R3 TOP-001-1 R1	Authority Letters	NERC received a request to clarify what criteria auditors consider when reviewing an authority letter.	
35		In Development	Periodic Data Submittals	Periodic Data Submittals	NERC received a request for clarification of whether violations would be mitigated if they were included in periodic data submittals.	
36		In Development	PRC-023	Applicability	This is in regards to PRC-023 and its applicability to Generator Owners that are not also transmission owners and/or distribution providers as stated in FERC Order 733.	
37		In Development	Roll-up Violations	Roll-up Violations	NERC received a request for clarification regarding whether the finding of non-compliance of one requirement would be applied across other Standards to which that requirement applies	
38		In Development	PER-002 R4	Training Hours	NERC received a request for clarification of how many training hours equals the required five days of training per PER-002 R4.	
39		Industry Comments/Industry Redline	DOE 417	DOE Form OE-417	The Department of Energy's (DOE) new online process for submitting the OE-417 disturbance reporting form does not automatically issue a copy to NERC or the Regions.	
40		Industry Comments/Industry Redline	BAL-003 R2	Frequency Bias Value	NERC received a request for clarification on the proper approach to determine Frequency Bias Setting.	
41		In Development	IRO-004 R1	Complete Dynamic Modeling	NERC received a request for clarification on whether complete dynamic modeling is required for next-day assessments.	
42		In Development	PRC-001 R1 PRC-001 R2 PRC-001 R4	Purpose Limits of Protection System Schemes	R1: Clarity on the use of the term "Generator Operator" (Not GOP's responsibility in company to know protection system)	
43		Industry Comments/Industry Redline	PRC-005 R2	Maintenance and Testing Procedure & Consistency Issues fm Key Reliability Standard Spot Check	NERC received several requests for clarification on what types of evidence are typically used to demonstrate compliance with Protection Systems[1] maintenance and testing in certain compliance areas	
44		In Development	TOP-001 R1 TOP-001 R2 TOP-001 R5 TOP-001-1 R8	System Emergency and Emergency Conditions	NERC received a request for clarification on the definition of system emergency.	
45		In Development	TPL-002 R1.3.10 TPL-003 R1.3.10 TPL-004 R1.3.7	Power Flow Models and Protection Systems Include Relay Devices as N-1	NERC received a request for clarification on whether the inclusion of redundant and backup protective system failures are required in power flow models.	

46		In Development	PER-002 and PER-003	Local v. Remote Operators	Remote (or local) control center operators are not certified; NERC position is that the main control center needs to be and that remote operators do not need to be.	
47		In Development	PRC-004	Relay in Abnormal Condition	Does operation of a relay during an abnormal condition constitute a misoperation?	
48		In Development	COM-001 R1.1-R1.4	Telecommuncation Redundancy	A single point of failure is not an automatic failure to comply with R1.1 - 1.3. If a facility is not sufficiently redundant, an entity is not automatically out of compliance with all R1 sub requirements but only R1.4.	
49		In Development	TOP-002 R14	Intentional Delays Notifying BA and RC	Define "Intentional Time Delay"	
50		In Development	BAL-002-0 R3, R1.1, R3.1, R4, R4.2	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.	We need to compare standards VRF with AML for consistency.	
51		In Development	CIP-004-2 R3 TOP-002-2a R2, R6, R8, R10, R19 TOP-002-2 R11	Background Checks System Conditions	Clarification of CIP-004-2 for Army Corps of Engineers; 7-yr Criminal Background Check? Asks for clarity on acceptable sources of ID verification, periodicity of ID verifications and 7-yr criminal checks; use gov't I-9; R6: Clarification of whether it is the responsibility of the BA to plan to meet CPS and DCS under unscheduled changes in the system configuration and generation dispatch. R2, R8, and R19: Clarity on BA obligations; the request for clarity seems to try to change the standard; "What do I have to do to comply?" R6 and R10: BA and TOP applicability.	
52		In Development	BAL-001-1 R1, BAL-002	Error Control	Clarification of whether the WECC Automatic Time Error Control Procedure (WATEC) violates Requirement 1 of BAL-001-0. Also see Standard's list for clarification "which disturbances are excluded from compiance evaluation".	
53		In Development		New Generation Facility	Whether an entity must be registered before connection and any testing	
54		In Development	PRC-008-1	UFLS Equipment	NERC should consider officially defining UFLS equipment as a Protection System or explicitly list what is included as part of UFLS equipment in order to remove confusion concerning this terminology. Adapt compliance applications for PRC-005 to the standard	
55		In Development	PRC-017-0 R1.1	define protection system	Include control circuitry as part of an SPS or formally regard an SPS to fall under the definition of a Protection System	
56		In Development	CIP-003 R1	Enforcing Subrequirements in Standards	If an entity may have one or more policies for any standard to demonstrate / define how it meets the requirements and sub-requirements how within the policy or policies the entity must clearly address each of the components laid out in the requirement and sub-requirements.	
57		In Development	PRC-011	UVLS	Adapt compliance applications for PRC-005 to the standard	
58		In Development	PRC-017	SPS	Adapt compliance applications for PRC-005 to the standard	
		RED= HIGH PRIORITY				
		In Queue	EOP-003-1 R3 & R5	Applicability	NERC Compliance received a request for clarity regarding the BA and TOP applicability with regard to compliance with the standard. Also - does this just apply to automatic load shedding or does it also apply to manual load shedding? (see interpretation list) it is fixed in the standard - as of 4/28 it has been approved by the BOT and is pending FERC filing	
		In Queue	IRO-002-1 R3	Applicability	Clarity requested from a region on the RC, BA, and TOP applicability	

		YELLOW= MEDIUM PRIORITY				
		In Queue	EOPs	Evidence Consistency	NERC Compliance received a request for clarification regarding communication capability, access, and verification using, RCIS, WECCnet, and FRCC	
		In Queue	TPL-003	Application	Application of Table 1 in TPL-003 and proper modeling of contingency events (ie: Category C vs. D)	
		In Queue	PRC-005-2	Define	Definition of a Calendar Year (CAN-0010)	
		In Queue	various	RRO requirements	Clarity on the RRO requirements and references in the currently approved NERC standards - ERCOT	
		In Queue	PRC-001		Internal Direction/Potential CAN discussion -Oceanview CI PRC-001	
		In Queue	IRO-006-4.1 R3	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.	
		In Queue	MOD-018	Applicability	Definition of a "non-member."	
		In Queue	Definition of BPS	Intrepretation of BPS definition	Application of current BPS definition in regard to attributing “one transmission source” to “load”	
		In Queue	RRO stnds	Clarity, Consistency	NERC Compliance received a request for clarity regarding the proper use of RRO.	
		PURPLE= NOT YET PRIORITIZED				
	Registered Entity	not yet prioritized	CIP-004 R3.1	criminal background checks	Clarification regarding the use of criminal history checks conducted by the FBI in support of the Access Authorization process mandated by the US Nuclear Regulatory Commission. Many companies rely on this process to support their CIP PRAs conducted under the CIP-004 Standard. We think a CAN addressing the acceptability of this practice would help provide clarity to the process.	
	Registered Entity	not yet prioritized		Management Console for Virtual Machine (VM) technology	With the Management Console having the capabilities for impacting the CCA VM Client, the Management Console should be considered a CCA. With the expanded usage of Virtual Machine technology it is in the best interest of the industry to have this clearly outlined to make sure the overall reliability of the BES is maintained.	
	Registered Entity	not yet prioritized	FAC-003-1, R1.2.2. (and subrequirements R1.2.2.1 & R1.2.2.2)	IEEE Standard conflicting with NERC standard	According to R1.2.2., “Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003”… A newer version of this IEEE standard was published in 2009 which contains clearances that are less restrictive than the 2003 version. Would a Transmission Owner be found non-compliant if they adopt the 2009 version, even though the requirement specifically refers to the 2003 version?	
	Registered Entity	not yet prioritized	IRO-005-3a R10	derived limits	The confusion with IRO-005-3a R10 is that it is not clear what the auditors would deem to be “derived limits” and what their approach would be to a small generator “…operating the Bulk Electric System.” What is also not clear is how auditors would approach independent entities even becoming aware of derived limits.	
	Region	not yet prioritized	CIP-002-4	Critical Asset losing its designation	If a Critical Asset loses its designation, as can be expected when the Bright Line criteria of CIP-002-4 changes the identification criteria for Critical Assets, when you lose the Critical Asset, you automatically lose the Critical Cyber Assets and the applicability of the CIP standards to any Cyber Assets previously protected at that no-longer critical asset. In this instance, do you have to conform to CIP-007/R7?	
	NERC/Registered Entity	not yet prioritized	PRC-001	FERC OER’s position on PRC-001 R1	Do system operators need a relay book [on the desk] with detailed engineering information on all the relay schemes in their area to be compliant with PRC-001 R1?	
	Region	not yet prioritized	multiple	Entities that have smaller generator units within the larger facility	Discuss whether the addition of a task force does would add anything.	
	Region/Registered Entity	not yet prioritized		definition of Radial Transmission	Source documents from multiple regions and from NERC demonstrate the inconsistent application of 'radial'.	

	Registered Entity	not yet prioritized	any CAN that contains definition of calendar year	definiinition of Calendar Year	If a standard requires the performance of an activity every 4 calendar years, and an entity performed the activity on January 1, 2008, would the entity meet the standard if the entity performed the activity anytime during 2012? Or would the completion be required on December 31, 2011?	
	Registered Entity	not yet prioritized	multiple CIP standards	hashing requirement	Possible Regional CAN: clarify hashing requirements	
	NERC/Region	not yet prioritized	TPL-003	application of Table 1	Confusion about what is an extreme event and misunderstanding of categorizing simulations (found in Table 1 of the TPL standards) on the final outcome after the fault was cleared instead on the initiating event/fault as required.	
	Registered Entity	not yet prioritized	CIP-003 R.1.1	address all requirments and subrequirements	Possible CAN: Within the policies the entity clearly address each of the components laid out in the requirement and sub-requirements. CAN will cover all standards.	
	NERC	not yet prioritized	PER-002-0	Operating Personnel Training	Possible CAN: Clarification may be necessary to ensure that Registered Entities understand what is expected and auditors have a consitent approach for determining compliance.	
	NERC	not yet prioritized	CFR	Commissioning Testing	Possible CAN: When will an entity be subject to compliance? Clarify that an entity must be registered before connection and any testing.	
	NERC	not yet prioritized	PRC-017-0	SPS Identificiation	Possible CAN: It would clarify things greatly if PRC-017-0 R1.1 specifically included control circuitry as part of an SPS or formally regarded an SPS to fall under the definition of a Protection System	
	NERC	not yet prioritized	PRC-008-0 R1	TO and DP with a UFLS Program	Possible CAN: Consider defining UFLS equipment as a Protection System or explicitly list what is included as part of UFLS equipment in order to remove confusion concerning this terminology.	
		not yet prioritized	PRC-004-1	Consistent Reporting of Protection System Misoperations	Possible CAN: Clarify the audit perimeter forMisoperations and CAPs to be reviewed. Also clarify if non-reportable Misoperations are subject to a compliance.	
		GREEN= LOWER PRIORITY				
		In Queue	FAC-003-1 R1	TVMP Changes	NERC received multiple requests for clarification on FAC-003-1 R1 regarding the allowable timeframe for implementation when an entity changes one TVMP plan based on normal trend to another TVMP plan based on clear cut. Once changed is the entity bound to implement immediately? Does the stnd provide for entities to have a transition period while changing TVMP plan? When they change a program, see below for TOP-002 and combine for one CAN	
		In Queue	TOP-002	Evidence	NERC Compliance received a request for clarification regarding different approaches to compliance when either the standard is less stringent than the registered entity's procedure or the auditing approach goes above what the standard requires. When a standard requires a registered entity to develop and implement its own plan, the auditor will audit to the registered entity's plan, even if it is superior to the requirements in the standard.	
Reasoning		**ISSUES THAT HAVE BEEN ADDRESSED/Retired CANs**				
AML Corrected		Adressed	BAL-005-0.1b R1	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.	
Issue too Broad		Adressed	CIP-002	CCAs	NERC Compliance received a request for clarification regarding different approaches to compliance and the scope of obligations on entities.	

Covered by CAN-0012 and CAN-0010		Adressed	CIP-005 R4	Cyber Vulnerability Assessment	NERC Compliance received a request for clarification on whether or not it is it appropriate to enforce this standard as requiring the entity to have performed a CVA prior to their Compliance Date.	
AML Corrected		Adressed	COM-001-1.1 R6	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.	
AML Corrected		Adressed	EOP-002-2.1 R7.2, R9	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.	
Submitted to Standards Issue Database		Adressed	FAC-003	Embedded References	NERC Compliance received a request for clarification about using IEEE standard by references in an enforceable standard when that IEEE standard has such stringent copyrights that can't be included in standard for auditors to audit to.	
CAN not appropriate vehicle but will hold for future		Adressed	FAC-008	Submitted Example of Excellence	NERC Compliance received a request for a best practice example of how to approach facility ratings.	
AML Corrected		Adressed	FAC-014-2 R2 and R4	Applicability	Inadvertent errors between stnds and compliance data sheets and database.	
AML Corrected		Adressed	TOP-001-1 R7.1	Applicability	Inadvertent errors between stnds and compliance data sheets and database.	
AML Corrected		Adressed	TOP-003-0 R1.2	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.	
AML Corrected		Adressed	TOP-005-1.1 R2 and R3	Applicability	Inadvertent errors between stnds VRF matrix and compliance Actively Monitored List - need review and verification.	
Discussed in Bulletin 2011-002 Audit Notifications		Adressed	PRC-008 R2	Evidence	NERC Compliance received a request for clarification on audit notifications and "data requests" for this standard.	
1 - Material covered in subsequent order		Adressed	INT-004-2 R1	Correction to VRF Matrix	This document provides notice of a correction in the Violation Risk Factor Matrix regarding compliance applicability of INT-004-2 R1.	
2- Material covered in subsequent order		Retired	TOP-003-0 R1.3	Correction to VRF Matrix	This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of TOP-003-0 R1.3.	
3- Material covered in subsequent order		Retired	IRO-006-4.1 R2	Correction to 2010 Actively Monitored Standards spreadsheet	This document provides notice of a correction in the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of IRO-006-4.1 R2.	
4- Material covered in subsequent order		Retired	IRO-004-1 R3	Correction to VRF Matrix and Actively Monitored spreadsheet	This document provides notice of a correction in the Violation Risk Factor Matrix and the 2010 Actively Monitored Standards spreadsheet regarding compliance applicability of IRO-004-1 R3.	
14 - Material covered in subsequent order		Addressed	IA & IC	IA & IC	Version 5 of the functional model refers to both IA and IC s interchangeably. Until all docs are fixed, they will be treated as the same.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0028 Comment Analysis Summary

TOP-006 R3 Reporting Responsibilities

CAN-0028 was originally posted as final on July 19, 2011. The original CAN provided instruction for assessing whether a Balancing Authority (BA) or Transmission Operator (TOP) fulfilled the requirements for reporting transmission or generation resources available for use to the applicable Reliability Coordinator (RC) and other affected BAs and TOPs under TOP-006 R1.2. The CAN has been revised to incorporate the direction provided by the NERC Board of Trustees in August of 2011 and was reposted as final on November 16, 2011.

The revised draft CAN was posted for industry comment on the NERC web site on October 10, 2011 and the comment period expired on October 31, 2011. During the comment period, NERC received positive comments from industry members stating that CAN-0028 accurately describes the reporting requirements for BAs and TOPs, the CAN accurately describes the evidence required to verify that the resource availability information was provided to the appropriate registered entities, and that CAN-0028 does not expand the applicability or requirements of the existing standard as drafted.

NERC received approximately eight comments from registered entities and three comments from trade associations, which are identified below. The main themes of the comments consisted of the following three categories: scope, effective date and evidence of compliance.

Scope

There were several recommended substantive changes to the CAN in regard to scope. Some commenters stated that CAN-0028 is unnecessary because the language of TOP-006 R1.2 clearly defines the reporting responsibilities of the applicable registered entities. The commenters further stated that the CAN should be withdrawn because the standard provides sufficient guidance.

In response to the comments, CAN-0028 was drafted to provide clarity with regard to reporting responsibilities. As currently written, TOP-006 R1.2 does not clearly decipher which function is responsible for reporting with regard to generation and transmission resources. The purpose of this CAN is to clarify and to instruct CEA staff to verify the proper evidence for the applicable function.

Other comments discussed the terminology of Bulk Power System (BPS) instead of Bulk Electric System (BES). The comments recommended that the CANs should be further improved, such that they all consistently use the NERC defined term BES and remove all references to the BPS. The rationale for the requested change is because the NERC Reliability Standards apply to the BES unless otherwise noted in the Applicability Section of a Standard. Moreover, there is no definition of BPS in the NERC Glossary of

Terms. The use of BPS in the CANs unnecessarily complicates and confuses the purported guidance therein.

In response to the comment, NERC has authority as the Electric Reliability Organization (ERO) to ensure the reliability of the Bulk Power System (BPS), as stated in section 215 of the Federal Power Act (FPA). The CANs reference BPS for this reason. Although BES is a defined term in the NERC Glossary, the BES is a subset of the greater BPS. Therefore, Compliance Application Notices will continue to use the terminology of BPS unless the standard specifies that it is applicable to the BES.

Another comment received was that the NERC Functional Model does not establish any responsibility for the TOP regarding generation resources, and BAs are not responsible for reporting transmission resources. For consistency, industry recommended that a similar statement be added for TOPs stating they are not responsible for reporting generation resources.

In response to the comments, the following language was added to the CAN for clarity:
"1. When auditing the BA, a CEA is to verify that the BA communicated generation resources, and 2. When auditing the TOP, a CEA is to verify that the TOP communicated transmission resources." This change explains the reporting responsibility for each registered entity, by function.

Effective Date

Several commenters believe that NERC should incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted by NERC as final and provides in that posting an implementation and effective date, which cannot be earlier than the posted date. There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

To clarify the effective date in CAN-0028, which is July 19, 2011, the effective date remains the same date as the original posting. Because the change to the CAN did not materially revise the compliance application in the previously posted version, it is a continuation of the original compliance application, and therefore this CAN was dated the same date as the earlier version.

Evidence of Compliance

Several commenters requested that the bullets be reworded to provide clarity in the Evidence of Compliance section, which was incorporated into the CAN. When a CEA audits a BA, they are to verify that the BA communicated generation resources. When a CEA audits a TOP, they are to verify that the TOP communicated transmission resources. This instruction provides guidance for consistent application to CEAs in the field.

Conclusion

The analysis spreadsheet for CAN-0028 has been posted on the NERC website. NERC received feedback that the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments. In order to provide increased transparency to the comment analysis phase of the CAN process, this document was created to supplement the information contained in the spreadsheet.

NERC staff thanks industry members for the time and effort put into providing the comments and feedback for CAN-0028. If you would like further discussion on CAN-0028, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
Bonneville Power Administration (BPA)
Constellation Energy (CEG)
MidAmerican Energy Company
Oncor Electric Delivery
Pepco Holdings, Inc.
PSEG
Southern Company

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
National Rural Electric Cooperative Association (NRECA)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Compliance Application Notice — 0028

~~Compliance Application:~~ TOP-006[1] R1.2 Reporting Responsibilities

Posted July ~~18~~19, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[2]
NERC
Regional ~~Entities~~ Entity (RE)
Transmission Operator~~s~~ (TOP)
Balancing ~~Authorities~~ Authority (BA)
~~Generator Operators (GOP)~~
Reliability Coordinator~~s~~ (RC)

Issue: What are resource reporting responsibilities for the ~~Balancing Authorities (~~BA~~)~~ s and ~~Transmission Operators (~~TOP~~s)~~ under TOP-006 R1.2?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether a BA or TOP has fulfilled the requirements for reporting transmission or generation resources available for use~~NERC received a request for clarification of whether a BA is responsible for reporting generation or transmission resources available for use~~ to RCs and other affected BAs and TOPs under TOP-006 Requirement ~~(R)~~R 1.2.

~~NERC also received a request for clarification of whether a TOP is responsible for reporting transmission or generation resources available for use to RCs and other affected BAs and TOPs under TOP-006 R1.2.~~

~~**Reliability Objective**~~
~~The Reliability Objective is to have current resource information available to ensure critical reliability parameters are monitored in real-time.~~

[1] ~~Version 1 of the standard is effective in the United States. Version 2 of the standard was approved by the NERC Board of Trustees on October 17, 2008 and went into effect for the Canadian Provinces pursuant to Canadian Memorandum of Understandings on April 1, 2009. Version 2 will become effective in the United States on the first day of the first calendar quarter, three months after FERC approval.~~
[2] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard and requirements.

Formatted: Centered

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com~~

Background

CEAs are to verify that ~~TOP-006 requires~~ BAs and TOPs ~~to~~ have reported the availability of generation or transmission resources under TOP-006. CEAs are to be aware that ~~; however,~~ BAs are not responsible for reporting transmission resources and that TOPs are not responsible for reporting generation resources..

Compliance Application

TOP-006 ~~-1 and TOP-006-2~~ provides, in pertinent part:

> ***R1.*** *Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.*
>
> …
>
> *R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.*

CEAs are to assess compliance for the responsible entity ~~W~~within the context of TOP-006 R1.2 as follows:

1. ~~the~~ A BA is the responsible entity for the reporting of generation resources available for use to the appropriate RC and the other affected BAs and TOPs; and
2. ~~the~~ A TOP is the responsible entity for the reporting of transmission resources available for use to the appropriate RC and the other affected BAs and TOPs.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from July 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

~~This CAN covers Versions 1 and 2 of the standard, is effective upon posting on the NERC Web site and will remain in effect until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable.~~

~~Providing~~ Evidence of Compliance

A CEA is to look for evidence that: ~~BA and TOP must be able to provide an auditor or Compliance Enforcement Authority:~~

1. When auditing the BA, verify that the BA communicated generation resources, and~~Evidence of its communications to its RC and other affected BAs and TOPs of the applicable generation or~~

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com~~

Formatted: Centered

~~transmission resources available for use. This evidence could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent. Each BA and TOP must have 90 days of historical data as evidence to provide an auditor or Compliance Enforcement Authority, and~~

2. When auditing the TOP, verify that the TOP communicated transmission resources. ~~Its processes, procedures, or other corroborating evidence to demonstrate compliance for the remainder of the audit period.~~

This evidence could include, but is not limited to: operator logs, voice recordings and electronic communications. A CEA is to verify the 90 days of historical data retained by the BA and TOP pursuant to the standard (*see* section D. Compliance, subsection 1.3 Data Retention of TOP-006).

To verify compliance for the remainder of the audit period, a CEA may review processes, procedures, or other evidence to demonstrate compliance.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of ~~Compliance Standards~~ Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

Ben Engelby
Sr. Compliance Interface and Outreach Specialist
ben.engelby@nerc.net
404-446-2560

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
July 19, 2011	Posted Final CAN	
November 16, 2011	Posted Revised CAN	Revised target audience to CEAs

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.~~
~~Princeton, NJ 08540~~
~~609.452.8060 | www.nerc.com~~

Formatted: Centered

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this compliance application notice is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com~~

Formatted: Centered

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0028

TOP-006 R1.2 Reporting Responsibilities

Posted: July 19, 2011
Revised: November 16, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Transmission Operator (TOP)
Balancing Authority (BA)
Reliability Coordinator (RC)

Issue: What are resource reporting responsibilities for BAs and TOPs under TOP-006 R1.2?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether a BA or TOP has fulfilled the requirements for reporting transmission or generation resources available for use to RCs and other affected BAs and TOPs under TOP-006 R1.2.

Background
CEAs are to verify that BAs and TOPs have reported the availability of generation or transmission resources under TOP-006. CEAs are to be aware that BAs are not responsible for reporting transmission resources and that TOPs are not responsible for reporting generation resources.

Compliance Application
TOP-006 provides, in pertinent part:

> ***R1.*** *Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.*
> …
>
> > ***R1.2.*** *Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.*

CEAs are to assess compliance for the responsible entity within the context of TOP-006 R1.2 as follows:

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard and requirements.

1. A BA is the responsible entity for the reporting of generation resources available for use to the appropriate RC and the other affected BAs and TOPs; and
2. A TOP is the responsible entity for the reporting of transmission resources available for use to the appropriate RC and the other affected BAs and TOPs.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from July 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[2] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

1. When auditing the BA, a CEA is to verify that the BA communicated generation resources, and
2. When auditing the TOP, a CEA is to verify that the TOP communicated transmission resources.

This evidence could include, but is not limited to: operator logs, voice recordings and electronic communications. A CEA is to verify the 90 days of historical data retained by the BA and TOP pursuant to the standard (*see* section D. Compliance, subsection 1.3 Data Retention of TOP-006). To verify compliance for the remainder of the audit period, a CEA may review processes, procedures, or other evidence to demonstrate compliance.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

Ben Engelby
Senior Compliance Specialist

[2] "Initiated" means that a registered entity has received notification of the upcoming audit.

ben.engelby@nerc.net
404-446-2578

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
July 19, 2011	Posted Final CAN	
November 16, 2011	Posted Revised CAN	Revised target audience to CEAs

Industry Comments for CAN-0028

Comment Topics	Main Points	Industry Suggestions
Supports CAN	The CAN is accurate as written	No suggestions
Scope	The NERC Reliability Standards apply to the BES unless otherwise noted in the Applicability Section of a Standard. Moreover, there is no definition of BPS in the NERC Glossary of Terms. The use of BPS in the CANs unnecessarily complicates and confuses the purported guidance therein.	Revised CANs should be further improved such that they all consistently use the NERC defined term BES and remove all references to the BPS.
Effective Date	The Effective Period of this CAN should not start before the date it is posted for industry's review.	Suggest implementation period for CAN
Evidence of Compliance	The CAN correctly states that BAs are not responsible for reporting transmission resources. This is consistent with the NERC Functional Model. Likewise, the NERC Functional Model does not establish any responsibility for the TOP regarding generation resources.	For consistency, we recommend a similar statement is written for TOPs stating they are not responsible for reporting generation resources.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0006 Comment Analysis Summary

EOP-005 R7 Verification of Restoration Procedure

CAN-0006 was originally posted as a final CAN on October 28, 2010. The original CAN provided descriptions regarding what constitutes "actual testing," "simulation" and stated that "tabletop testing" did not fulfill the requirements of EOP-005 R7. NERC received a request to review this CAN regarding the compliance application in regards to tabletop testing by registered entities that do not have a technical component to their restoration plan, a situation that was occurring in one region of the United States.

The revised CAN has been reposted as final on November 11, 2011, and incorporates the results of the review conducted for tabletop testing as well as the direction provided by the NERC Board of Trustees in August of 2011.

The draft of the revised CAN was posted for industry comment on the NERC web site on September 1, 2011 and the comment period expired on September 21, 2011. NERC received approximately 20 comments from various industry stakeholders and trade associations, which are identified below. The main themes of the comments consisted of the following five categories: errata changes, the scope of the CAN, the effective date language and the types of evidence the Compliance Enforcement Authorities (CEA) are to verify.

Errata

The recommended errata changes were revised in order to provide correct spelling in a footnote and clarity in the title of the CAN.

Scope

There were several recommended substantive changes to the CAN in regard to the scope of the compliance guidance. The commenters stated that CAN-0006 appears to expand the requirement and many of the draft CAN details are outside the context of what is intended by the initial issue. The suggestion was received for revising the CAN to only provide what is an acceptable test or simulation to verify the restoration procedure.

There were several suggestions from industry that were incorporated. The CAN was revised in response to the comments that "tabletop testing", or simulated restoration exercises which take place without actual equipment, would be sufficient to comply with the requirement under specific circumstances; these circumstances are described in the CAN. Further, based on commenter's suggestions, the ambiguous terms "adequacy of the verification" and "close enough" were removed from the CAN. Some commenter's disagreed with the use of the term "electronic simulation", stating

it is not required by the standard. The original CAN had incorporated this term to inform industry what type of simulation would fulfill the requirement; the revised CAN continues use of the term to distinguish it from "tabletop testing" and to instruct CEAs when each type of simulation should be deemed to fulfill the requirement. There were other comments stating that the types of evidence a CEA would require took the CAN out of scope – these are discussed below in the "Evidence of Compliance" section.

Effective Date

Several commenters believe that NERC should incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted by NERC as final and provides an effective date which cannot be earlier than the posted date. There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

To clarify the effective date in CAN-0006, which is October 25, 2010, the effective date remains the same date as the original posting. Because the change to the CAN did not materially revise the compliance application in the previously posted version, it is a continuation of the original compliance application, and therefore this CAN was dated the same date of the earlier version. This CAN provides greater flexibility for how a registered entity demonstrates compliance with the standard by including tabletop testing, under specific circumstances, for verification of restoration procedures.

Evidence

Commenters had questions regarding the Evidence of Compliance section. Particularly, several industry members stated that there were other equally effective means that illustrate the registered entity fulfills the intent of the requirement. NERC staff took this suggestion and added the language, "such evidence may include," to notify the CEAs that they should take into account that the evidence listed was not an exhaustive list. The final sentence in the CAN also provides other types of evidence that a CEA may verify to obtain reasonable assurance of the entity's compliance.

In the circumstance that a registered entity does not have a technical role in restoring the system, a letter from the TOP whose restoration procedure includes the registered entity is evidence that a CEA will require to verify that a registered entity does not have to do actual or electronic simulation testing. The letter provides the CEA with reasonable assurance that the registered entity does not have a technical component to its restoration procedure and that there is an entity (the TOP) covering the technical restoration issues so no reliability gap exists.

Conclusion

The analysis spreadsheet for CAN-0006 is also posted on the NERC website. While the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments, it is hoped that this document will supplement that

information. Feedback from all sources is key and NERC staff thanks industry for the time and effort put into providing that feedback. If you would like further discussion on CAN-0006, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
Bonneville Power Administration (BPA)
Chelan County PUD
Constellation Energy (CEG)
Dominion Resources Services, Inc.
Farmington Electric Utility
Florida Municipal Power Authority (FMPA)
Fort Pierce Utilities Authority (FPUA)
Indeck Energy Services
Kansas City Power & Light (KCP&L)
Lakeland Electric
MidAmerican Energy Company
Progress Energy (PGN)
Southern Company
Westar Energy
Xcel Energy

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
ISO/RTO Council's Standard Review Committee (IRC SRC)
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
National Rural Electric Cooperative Association (NRECA)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0006

EOP-005 R7 Verification of Restoration Procedure

Posted: October 25, 2011
Reposted: November 11, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Balancing Authority (BA)
Transmission Operator (TOP)

Issue: In regard to evidentiary requirements regarding actual testing or by simulation, what constitutes an actual test and what constitutes a simulation?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether:

1) an entity has verified its restoration procedure "by actual testing or by simulation," as required by EOP-005-1 R7, and

2) the use of a third-party vendor impacts a registered entity's obligation under the standard.

Compliance Application
EOP-005-1 R7 provides, in pertinent part:

> ***R7****. Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.*

CEAs are instructed to obtain evidence that a registered entity verified its restoration procedure by actual testing or by simulation.

A CEA is not to assess the circumstances under which actual testing or simulation has occurred. Rather, a CEA is to focus solely on the registered entity's testing or simulation that verifies whether the entity's restoration procedure restores its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system.[2]

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards or requirements.
[2] As specified in EOP-005-1 R1

The size of an entity **does not** determine whether actual testing or simulation is required; therefore, CEAs are to assess whether registered entities have verified their procedures by actual testing, simulation, or some combination of the two, by the instructions provided below.

Regarding actual testing: Actual testing is an option that a TOP or BA may use to verify steps of the restoration procedure to demonstrate the TOP's or BA's ability to establish a Cranking Path with clearly identified Loads and then starting a generating unit using that Cranking Path. The intent is to demonstrate that the Cranking Path can be successfully established.

Actual testing may also include use of the restoration procedure to restore a portion of the system where the responsible entity uses logs, Historian[3] data, and other documentation to verify that the step(s) of the restoration procedure[4] worked, based on actual operations (including things such as verification of fuel sources). While the actual testing may be different from what is expected to occur in an actual restoration, a CEA is to assess whether the attributes necessary to verify the adequacy of the system restoration procedure are included.

Regarding simulation: Simulation is an option that the TOP or BA may use to verify its restoration procedure. Simulation may include electronic simulation, which is a simulation of what is expected to actually occur during system restoration. Simulations may be conducted at a control center using the system operator's workstation or other facilities. Simulation may also include a walk-through simulation of a restoration procedure that has been tested using previous electronic simulation methods. In both cases, a CEA is to verify that the restoration scope and the results of the simulation replicate what would actually occur, including that decisions made during the simulation would be effective in actual restoration.

An ***electronic simulation***[5] may include an engineering analysis, which uses engineering analytical methods and practices that provide results that are consistent with actual measurements to verify the restoration procedure. The analysis is performed in a simulation environment, and the restoration procedure is verified by showing that the steps in the restoration procedure do not place load and generation out of balance. The level of simulation required depends on the actual restoration procedure, the facilities being simulated, and the contingencies considered. This may require the use of power flows[6] to verify steady state conditions; transient stability analysis to verify the dynamic performance; electromagnetic transient analysis to verify switching operations; and an overall analysis to tie the results of these studies into a coherent determination of whether the proposed restoration actually achieves its desired goal.

[3] Historian Software provides high-speed data capture

[4] Restoration procedures are a guide to use during a restoration event and not a sequence of tasks to be performed in a numerical order. System conditions and other activities in other areas of the system will affect the restoration process.

[5] Training or development systems should be visibly and distinctly different from the live EMS control screens. See NERC Lesson Learned, EMS/SCADA Systems – Training System versus Live EMS Screen.

[6] "Power flows" refers to power flow studies which, for the purpose of the CAN, are interchangeable with load flow studies.

A ***walk-through simulation of the actual equipment*** using the restoration procedure without actually performing the actions may include, but is not limited to, the use of equipment such as control room consoles, control panel illustrations, one line diagrams, or other diagrams that identify system components. The walk-through simulation can verify some attributes of the procedure by simulating procedure steps, such as staff pointing to physical breakers, one line drawings or light indicators and stating expected results when actions are taken. This type of simulation relies on the results of engineering studies performed using the same system conditions as proposed in the restoration procedure to verify expected steady state, transient stability and electromagnetic transient results. Regardless of the type of simulation, the desired outcome is to verify that the restoration procedure is viable in the event of a partial or total shutdown of the bulk power system (BPS).

A ***simulated restoration exercise that takes place without actual equipment***[7] (whether by electronic or walk-through simulation) would not normally be considered verification "by actual testing or simulation," as required by the standard. As described below, a registered entity may fulfill the requirement by conducting a simulation restoration exercise(s) that takes place without actual equipment. For a walk-through simulation conducted without actual equipment, the CEA is instructed to verify that the registered entity has a letter from either its BA or a TOP whose restoration procedure includes the registered entity, stating that:

1. the registered entity does not have a technical component to its restoration plan and
2. the registered entity's restoration is included in the BA's or TOP's restoration plan.

Regarding outsourcing of reliability requirements and coordination: A BA or TOP may use a third party to conduct a simulation of its restoration procedure. The third party may be a contractor or another registered entity, such as a TOP. In such cases, a CEA is to verify that the registered entity has a copy of the restoration procedure applicable to its facilities, documentation to show that the restoration procedure was verified by simulation, and the simulation results.

Additional information on compliance responsibility and accountability regarding the delegations of performance of reliability-related tasks is contained in the "NERC Compliance Public Bulletin #2010-004 Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity."[8]

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from October 25, 2010, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

[7] Simulated restoration exercises conducted without actual equipment may be considered "tabletop exercises."
[8] http://www.nerc.com/files/2010-004%20v1%200.pdf

For any enforcement action in process and for audits that have been initiated,[9] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

CEAs are to assess evidence to obtain reasonable assurance of the entity's compliance. Such evidence may include:

- engineering analytical methods and practices
- power flows to verify steady state conditions
- transient stability analysis to verify the dynamic performance
- electromagnetic transient analysis to verify switching operations

CEAs are to verify that all of the evidence replicates actual events. Additionally, CEAs may accept actual responses to system disturbances, long-term dynamics, or other modeling tools or techniques not listed in this notice to obtain a reasonable assurance that a registered entity is compliant with this requirement.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

[9] "Initiated" means that a registered entity has received notification of the upcoming audit.

Revision History

Posted Date	Action	Revision
October 25, 2010	Posted Final CAN	
November 11, 2011	Posted Revised CAN	Revised to provide for simulated restoration exercise that takes place without actual equipment and target audience to CEAs

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice

~~Compliance Application:~~ EOP-005-1 R7 Verification of Restoration Procedure

Posted October 25, 2010
Reposted: November 10, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Balancing Authority (BA)
Transmission ~~Operators~~Operator (TOP)

Issue: In regard to evidentiary requirements regarding actual testing or by simulation, what constitutes an actual test and what constitutes a simulation? ~~Evidentiary Requirements regarding Actual Testing or by Simulation~~
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether: ~~Registered entities and Regional Entities request that NERC provide informal guidance on the following issues:~~

1) an entity has verified its restoration procedure "by actual testing or by simulation," as required by EOP-005-1 R7, and ~~What constitutes a test?~~

2) the use of a third-party vendor impacts a registered entity's obligation under the standard. ~~What constitutes a simulation?~~

~~How does the use of a third-party vendor impact the registered entity's obligation to coordinate its restoration plan, as required by EOP-005-1 R4?~~

~~What types of evidence may demonstrate that a registered entity has verified its restoration procedure "by actual testing or by simulation," as required by EOP-005-1 R7?~~

~~Also, registered entities and Regional Entities request informal guidance on whether the size of an entity determines its use of actual testing or simulation when verifying its restoration procedure.~~

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards or requirements.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

~~**Reliability Objective**~~

~~The reliability objective of EOP-005-1 R7 is to ensure that registered entities verify, by actual testing or by simulation, that procedures are in place and will work to restore the system in the event of a partial or total shut-down of their respective area of the bulk power system.~~

Compliance Application

EOP-005-1 R7 provides, in pertinent part:

> ***R7***. *Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.*

CEAs are instructed to obtain evidence that a registered entity verified its restoration procedure by actual testing or by simulation. A CEA is not to assess the circumstance under which actual testing or simulation has occurred. Rather, a CEA is to focus solely on the registered entity's testing or simulation that verifies whether the entity's restoration procedure restores its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system.[2]

The size of an entity does not determine whether actual testing or simulation is required; therefore, CEAs are to assess whether registered entities have verified their procedures by actual testing, simulation, or some combination of the two, by the instructions provided below.

~~Registered entities must provide evidence to demonstrate to the Compliance Enforcement Authority that they have verified their restoration procedures by actual testing or by simulation.~~

~~The standard does not provide the circumstances under which actual testing or simulation must occur as long as the testing or simulation results in verifying the adequacy of the system restoration. The size of an entity also does not determine whether actual testing or simulation is required. Registered entities may verify their procedures by actual testing, simulation, or some combination of the two.~~

Regarding actual testing: Actual testing is an option that a ~~Transmission Operator~~TOP or ~~Balancing Authority~~BA ~~can~~ may use to verify steps of the restoration ~~elements of a~~ procedure to determine the TOP's or BA's ability to establish a Cranking Path with clearly identified Loads and then starting a generating unit using that Cranking Path. The intent is to demonstrate that the Cranking Path can be successfully established.

[2] As specified in EOP-005-1 R1

Actual testing may also include use of the restoration procedure to restore a portion of the system where the responsible entity uses logs, Historian dad, and other documentation to verify that the step(s) of the restoration procedure[3] worked, based on actual operations (including things such as verification of fuel sources). While the actual testing may be different from what is expected to occur in an actual restoration, a CEA is to assess whether the attributes necessary to verify the adequacy of the system restoration procedure are included.

~~s, but is not limited to, a physical test of the procedure, such as operating Bulk Electric System Elements in order to demonstrate the ability to 1) establish a Cranking Path with clearly identified loads that are part of the underfrequency load shedding or undervoltage load shedding and 2) start a generating unit using that Cranking Path. The intent is to simulate and verify that the cranking path can be successfully and efficiently established within anacceptable voltage and frequency range. Actual testing may also include using a procedure to restore the system (*i.e.*, relay trip), and retaining logs and data (historian data), and other documentation to verify that the element(s) of the procedure worked based on actual operations (including verification of fuel sources), in the case of a system event. While the actual testing may be different from what is expected to occur in an actual restoration, the aspects necessary to verify the adequacy of the system restoration procedures must be included.~~

Regarding simulation: Simulation is an option that the ~~Transmission Operator~~TOP or ~~Balancing Authority~~BA ~~can~~ may use to verify its restoration procedure. Simulation ~~can~~ may include electronic simulation, which is a simulation of what is expected to actually occur during ~~real-time~~ system restoration. Simulations ~~are~~ may be conducted at a control room center using the system operator's workstation or other facilities. ~~on the Transmission Operators' or Balancing Authorities' workstations.~~ Simulation ~~can~~ may also include a walk-through simulation of a ~~on~~ restoration procedure that has been tested using previous electric simulation methods. ~~plans that have been tested using previous electronic simulation methods.~~ In both cases, a CEA is to verify that the restoration scope and the results of the simulation replicate ~~must be close enough to~~ what would actually occur, including that decisions made during the simulation would be effective in actual restoration. ~~so that decisions and restoration procedures made with the results would be effective in real-time restoration.~~

[3] Restoration procedures are a guide to use during a restoration event and not a sequence of tasks to be performed in a numerical order. System conditions and other activities in other areas of the system will affect the restoration process.

An ***electronic simulation***[4] ~~can~~ may include ~~the use of~~an engineering analysis, which uses ~~using~~ engineering analytical methods and practices that provide results that are consistent with actual measurements to verify the restoration procedure. The analysis is performed in a simulation environment, and the restoration procedure is verified by showing that the steps in the restoration procedure do not place load and generation out of balance. ~~programmed into a real-time simulation in the control room or its workstations, and the restoration procedure is verified by showing that the simulating procedure steps do not result in any steady state or transient stability criteria violations when compared to the output of the programmed analysis into the simulator.~~ The level of simulation required depends on the actual restoration procedure, ~~nature of the restoration procedure,~~ the facilities being simulated, and the contingencies being considered. This may require the use of power flows[5] ~~load flows~~ to verify steady state conditions; transient stability analysis to verify the dynamic performance; electromagnetic transient analysis to verify switching operations; and an overall analysis to tie the results of these studies into a coherent determination of whether ~~if~~ the proposed restoration actually achieves its desired goal.

A ***walk-through simulation on the actual equipment*** using the restoration procedure without actually performing the actions ~~can~~ may include, but is not limited to, the use of things such as control room consoles, control panel illustrations, one line diagrams, or other diagrams that identify system components. The walk-through simulation can verify some ~~aspects~~ attributes of the procedure by simulating procedure steps, such as staff pointing to physical breakers, one line drawings, light indicators and stating expected results when actions are taken. This type of simulation relies on the results of engineering studies performed using the same system conditions as proposed in the restoration procedure to verify expected steady state, transient stability and electromagnetic transient results. Regardless of the type of simulation, ~~its~~ the desired outcome is to verify that the restoration procedure is viable~~s to restore the system are viable~~ in the event of a partial or total shut down of the ~~bulk~~ Bulk P~~p~~ower S~~s~~ystem (BPS).

A ***simulated restoration exercise that takes place without actual equipment***[6] (whether by electronic or walk-through simulation) would not normally be considered verification "by actual testing or simulation," as required by the standard. As described below, a registered entity may fulfill the requirement by conducting a simulation restoration exercise(s) that takes place without actual equipment. For a walk-through simulation conducted without actual equipment, the CEA is instructed to verify that the registered entity has a letter from either its BA or a TOP whose restoration procedure includes the registered entity, stating that:

[4] Training or development systems should be visibly and distinctly different from the live EMS control screens. See NERC Lesson Learned, EMS/SCADA Systems – Training System versus Live EMS Screen.
[5] "Power flows" refers to power flow studies which, for the purpose of the CAN, are interchangeable with load flow studies.
[6] Simulated restoration exercises conducted without actual equipment may be considered "tabletop exercises."

1. the registered entity does not have a technical component to its restoration plan and
2. the registered entity's restoration is included in the BA's or TOP's restoration plan.

~~Regarding table tops: A table top exercise that takes place without actual equipment (whether by electronic or walk-through simulation) would not be considered "by actual testing or simulation," as required by the standard. However, table top exercises may provide training value with respect to the coordination of tasks and communication between operating personnel.~~

Regarding outsourcing of reliability requirements and coordination: A BA or TOP may use a third party to conduct a simulation of its restoration procedure. The third party may be a contractor or another registered entity, such as a TOP. In such cases, a CEA is to verify that the registered entity has a copy of the restoration procedure applicable to its facilities, documentation to show that the restoration procedure was verified by simulation, and the simulation results.

Additional information on compliance responsibility and accountability regarding the delegations of performance of reliability-related tasks is contained in the "NERC Compliance Public Bulletin #2010-004 Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity."[7]

~~Requirement 4 addresses coordination with regard to the restoration plan. If a registered entity's restoration procedure includes coordination with a third party because that registered entity outsourced the initiation, or partial or full implementation, of R7 to another registered entity or non-registered third party contractor or consultant, the verification of the procedure should demonstrate that the procedures to coordinate are in place and the restoration procedure to restore the system is viable in the event of a partial or total shut down of the bulk power system. In such cases, the registered entity must have and be able to produce a copy of the restoration procedure applicable to its facilities as well as the backup documentation to support the conclusion. For example, Transmission Owner A is being audited and it partially owns blackstart facilities with Transmission Owner B. The restoration procedures for the blackstart facilities are developed by Transmission Owner B and are contained in Transmission Owner B's procedures, Transmission Owner A must have and produce a copy in the audit as well as the backup documentation to support the conclusion and must demonstrate that the system restoration procedure was verified by "actual testing or by simulation."~~

[7] http://www.nerc.com/files/2010-004%20v1%200.pdf

~~Additional information on compliance responsibility and accountability regarding the delegations of performance of reliability-related tasks is contained in the "NERC Compliance Public Bulletin #2010-004 Guidance for Entities that Delegate Reliability Tasks to a Third Party Entity."[8]~~

~~**Non-exclusive list of Evidence**~~**Effective Period for CAN**

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from October 25, 2010, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[9] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

The following is a non-exclusive list of evidence that has been used to meet R7:

- engineering analytical methods and practices;
- load flows to verify steady state conditions;
- transient stability analysis to verify the dynamic performance; and
- electromagnetic transient analysis to verify switching operations.

All of the evidence relied on must be shown to duplicate actual events. Additionally, registered entities may use actual responses to system disturbances, long-term dynamics, one lines, or other modeling tools or techniques not listed in this notice to demonstrate compliance with this requirement.

Evidence of Compliance

CEAs are to assess evidence to obtain reasonable assurance of the entity's compliance. Such evidence may include:

- engineering analytical methods and practices
- power flows to verify steady state conditions
- transient stability analysis to verify the dynamic performance
- electromagnetic transient analysis to verify switching operations

~~[8] http://www.nerc.com/files/2010-004%20v1%200.pdf~~

[9] "Initiated" means that a registered entity has received notification of the upcoming audit.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CEAs are to verify that all of the evidence replicates actual events. Additionally, CEAs may accept actual responses to system disturbances, long-term dynamics, or other modeling tools or techniques not listed in this notice to obtain a reasonable assurance that a registered entity is compliant with this requirement.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the NERC Reliability Standards as they may be amended from time to time. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of this Compliance Application Notice is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

Industry Comments for CAN-0006

Comment Topics	Main Points	Industry Suggestions
Errata Changes	Spelling and grammatical changes	Change title, check spelling
Scope	CAN appears to expand the requirement by requiring entities to provide transient stability and electromagnetic transient studies, which may not be necessary to ensure an entity's restoration plan can achieve its desired goal. This effort and coordination will likely be halted if NERC provides guidance to CEAs that "table top" exercises would not suffice in an audit. Many of the draft CAN details are outside the context of what is intended by the initial issue. Suggest revising this CAN to only providing what is an acceptable test or simulation to verify the restoration procedure. CAN-0006 goes beyond simple guidance by implying an interpretation of "simulations" to include steady state, dynamic and EMTP studies. Interpretations of standards should go through the formal interpretation process. The CAN over-reaches and changes the standard in at least three ways: 1. By adding a requirement to verify adequacy 2. By requiring "electronic simulation" 3. By adding a requirement for a letter of approval in order to use a valid interpretation of "simulation"	CAN 0006 should state that a TOP and BA need to "verify the(ir) restoration procedure" by actual testing (of the restoration procedure, ie: by training on the restoration procedure, by review of the restoration procedure to assure accuracy, etc.) or by simulation (of the restoration procedure, ie: by table top exercise, by practicing the implementation of the procedure, etc.).
Effective Date	Any version of a CAN should become effective only after it is public posted by NERC as final and provides in that posting an implementation and effective date which cannot be earlier than the posted date.	The effective date of this revised CAN should be the date it is posted as final, not the previous date of October 25, 2010.
Evidence	Other equally effective means that illustrate the registered entity fulfills the intent of the requirement.	One could interpret this section to mean that an entity must have all four types of studies for its system.
Applicability	The CAN should make it clear that the only role of the BA is to support the TOP in the restoration. This requirement was never intended to apply to the BA.	TOP-002-2b includes an interpretation of R10 that clarifies the BA can have no role in meeting SOLs and IROLs outside of following the orders of the TOP. FERC has proposed to improve the interpretation.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0009 Comment Analysis Summary

FAC-008 and FAC-009 Facility Rating and Design Specifications

CAN-0009 was originally posted on January 7, 2011 following the October 7, 2011 *Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings* to provide guidance whether registered entities should self-report a violation of either FAC-008-1 R1 or FAC-009-1 R1 when constructed Facilities do not match a registered entity's design specifications. This CAN has been redrafted to implement the NERC Board of Trustees (BOT) guidance for CANs that was provided at the August 3, Member Representative Committee (MRC)/BOT meeting.

The draft revised CAN was posted for industry comment on the NERC web site on September 23, 2011 and the comment period expired on October 14, 2011.

NERC received approximately 20 comments from various industry stakeholders and trade associations, which are identified by name below. The main themes of the comments consisted of the following five categories: errata changes, scope, effective date, evidence of compliance and the CAN process.

Errata

The recommended errata change was to list the entire Requirement R1.3 to avoid confusion. For clarity, the CAN now has the entire requirement listed. NERC staff thanks the commenters for pointing out this recommended change in the CAN.

Scope

There were several recommended substantive changes to the CAN in regard to scope. The commenters stated that CAN-0009 goes beyond FAC-008 AND FAC-009 and Compliance Enforcement Authority (CEA) staff should not be instructed to verify evidence that field conditions match the design of the facilities.

In response to the comments, CAN-0009 addresses operational Facilities with discrepancies between design specifications used for the development of ratings and actual field conditions that are outside the entity's design tolerances. While the importance of correcting these discrepancies within the above dates cannot be overstated, any such discrepancy is not necessarily a violation of the NERC Reliability Standards. CAN-0009 reinforces the premise that the recommendation was based on improving reliability, not creating compliance enforcement actions. It also provides for these Possible Violations to be held in abeyance for determination after the registered entity's assessment is complete, with strong considerations for a zero-dollar penalty or resolution through the Find, Fix and Track (FFT) recording mechanism.

Effective Date

Several commenters believe that NERC should to incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted by NERC as final and provides in that posting an implementation and effective date which cannot be earlier than the posted date. There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

To clarify the effective date in CAN-0009, which is April 19, 2011, the effective date remains the same date as the original posting. Because the changes to the CAN did not add any changes to the compliance application from the previously posted version, this CAN was dated to remain in effect as if it were posted at the time of the earlier version.

Evidence of Compliance

Several commenters believe that there is no recommended evidence for either the CEAs or registered entities to properly evaluate compliance with the standard. This section is more focused on enforcement action and penalty assessment and should not be part of this CAN. This entire section should be revised to provide recommended evidence and not focus on enforcement actions or penalty assessments.

In response to the comments, the CAN was revised to instruct CEAs to review each registered entity's Facility Rating Methodology (FRM). Due to the unique nature of each FRM, the CEAs are to review these methods to determine whether the entity's FRM included addressed the actual physical application of the design criteria in the field for individual Facilities and/or actual clearances for individual Facilities.

Further, CEAs are to strongly consider a registered entity's concerns for reliability, and they are to consider several factors and exercise discretion before making a determination of a possible violation. Also, the CAN points out that any discrepancy may result in a zero-dollar penalty or FFT resolution.

CAN Process

Several commenters stated that NERC was working at an unreasonable pace for revising and reposting all of the final CANs. The comments pointed out that due to such volume, NERC may not receive the constructive input from stakeholders that they could have under a more measured approach. There was an acknowledgement of understanding, in that the current volume is a unique task resulting from the NERC Board of Trustees direction, but it results in a strain on industry resources to review and comment on all postings. The suggestion was a request for more reasonable review opportunities going forward.

In response to the comments, NERC staff is aware that the volume of CANs being posted for comment has been cumbersome. The revision process has given industry another opportunity to comment on

previously posted final CANs, and NERC staff has spent many hours in preparing the drafts and reviewing the comments received from industry. The revised CANs should be complete by the end of 2011, and going forward, the industry comment periods will be handled in a much more manageable pace. If any industry members need more time to submit CAN comments, they are welcome to request an extension by sending an email to cancomments@nerc.net. We understand the situation and are trying our best to accommodate all requests.

Conclusion

NERC staff thanks industry for providing invaluable feedback to the CAN process and to CAN-0009. If you would like to discuss CAN-0009, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
Ameren Services
Bonneville Power Administration (BPA)
Constellation Energy (CEG)
Dominion Resources Services, Inc.
Florida Municipal Power Authority (FMPA)
Fort Pierce Utilities Authority (FPUA)
Ingleside Cogeneration/Occidental
Kansas City Power & Light (KCP&L)
Madison Gas and Electric
MidAmerican Energy Company
NPCC Entities (industry)
Pepco
Southern Company
Westar Energy
Western Area Power Administration

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
National Rural Electric Cooperative Association (NRECA)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0009

FAC-008 and FAC-009 Facility Ratings and Design Specifications

Posted: January 7, 2011
Revised: November 11, 2011

Primary Interest Groups

Compliance Enforcement Authority (CEA)[1]
Transmission Owner (TO)
Generation Owner (GO)
Regional Entity
NERC

Issue: Should CEAs find a violation of FAC-008 R1 or FAC-009 when it is determined that constructed Facilities do not match design specifications?

For the purpose of aiding CEAs, this CAN provides instruction for assessing compliance with FAC-008 R1 and FAC-009 R1 when an entity's constructed Facilities do not match its design specifications.

Summary

Due to the Recommendation to Industry (discussed below), possible non-compliances may be discovered for registered entities that had developed the most robust Facility Rating Methodologies (FRMs). This CAN reinforces the premise that the recommendation was based on improving reliability, not creating compliance enforcement actions. It also provides for these Possible Violations to be held in abeyance for determination after the registered entity's assessment is complete, with strong considerations for a zero-dollar penalty or resolution through the Find, Fix and Track (FFT) recording mechanism.

Background

NERC's *Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings*[2] (Recommendation) identified a reliability concern due to Facilities in the field not matching a registered entity's design specifications. This Recommendation contained a call to action for industry with key dates, which were revised on November 29, 2010, as follows:

- October 20, 2010 – Acknowledge receipt of Recommendation
- October 28, 2010 – Attend Webinar (optional)
- November 29, 2010 – Attend second Webinar (optional)

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] Issued on October 7, 2010

- January 18, 2011– Assess impact of the alert and provide an action plan, as required, to NERC, including any extension requests for completing assessments (originally December 15, 2010)
- May 12, 2011 – Attend Webinar (optional)
- Complete assessments - Identify all discrepancies between the design and actual field conditions that are outside the registered entity's design tolerances and report those discrepancies to NERC, applicable Reliability Coordinators (RCs), Transmission Operators (TOPs), and Regional Entities by:[3]
    1. ***December 31, 2011 for High Priority Facilities***
    2. ***December 31, 2012 for Medium Priority Facilities***
    3. ***December 31, 2013 for Lowest Priority Facilities***
- Remediation to correct all issues identified during the assessment should occur as quickly as practical but within one year of identification; otherwise, entities are to obtain an approval from their respective Regional Entity to extend the deadline.

In addressing this important reliability Recommendation, registered entities may discover operational Facilities with discrepancies between design specifications used for the development of ratings and actual field conditions that are outside the entity's design tolerances. While the importance of correcting these discrepancies within the above dates cannot be overstated, any such discrepancy is not necessarily a violation of the NERC Reliability Standards.

Nevertheless, such a discrepancy may contribute to a possible violation of one or more of the following requirements: FAC-008-1 R1 or FAC-009-1 R1 or R2, based on the facts and circumstances specific to each instance, as described below. NERC encourages each registered entity to closely examine its Facility Ratings methodology (FRM) required by FAC-008-1 R1 and the application of its FRM as required by FAC-009 R1 and R2 to determine if it is in compliance.

Compliance Application

FAC-008

FAC-008-1 requires a registered entity to have a documented FRM for developing Facility Ratings of its solely and jointly owned Facilities.

FAC-008 provides, in pertinent part:

> ***R1.*** *The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:*

[3] All assessments were originally due on April 7, 2011.

> ***R1.1.*** *A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.*
>
> ***R1.2.*** *The method by which the Rating (of major BES equipment that comprises a Facility) is determined.*
>
> > ***R1.2.1.*** *The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.*
> >
> > ***R1.2.2.*** *The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.*
>
> ***R1.3.*** *Consideration of the following:*
>
> > ***R1.3.1.*** *Ratings provided by equipment manufacturers.*
> >
> > ***R1.3.2.*** *Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).*
> >
> > ***R1.3.3.*** *Ambient conditions.*
> >
> > ***R1.3.4.*** *Operating limitations.*
> >
> > ***R1.3.5.*** *Other assumptions.*

CEAs are to verify whether a registered entity's FRM included consideration of the equipment manufacturer's provided ratings (R1.3.1), design criteria (R1.3.2), ambient conditions (R1.3.3), operating limitations (R1.3.4) and other assumptions (R1.3.5) in its FRM.

FAC-009 R1

FAC-009-1 R1 requires TOs and GOs to establish Facility Ratings for their solely and jointly owned Facilities that are consistent with the associated FRM, which is required under FAC-008 R1.

FAC-009 provides, in pertinent part:

> ***R1.*** *The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.*

Therefore, in order for a CEA to determine whether a registered entity's Facility Ratings were established pursuant to the entity's FRM, the CEA is to first verify whether the entity's FRM addresses design criteria for Transmission Facilities, including clearances, and if so, whether the design criteria and clearances that are included are:

1) the actual physical application of the design criteria in the field for individual Facilities and/or actual clearances for individual Facilities; ***or***

2) did not include the actual physical application of the design criteria in the field for individual Facilities and/or actual clearances for individual Facilities. In this case, the entity may have stated design criteria broadly as general policy requirements.

If the CEA determines that Option 1 applies, i.e. where an entity's FRM requires the inclusion of the actual clearances or the physical applications of design criteria in the field for individual Facilities in the calculation of the Facility Rating:

- If the entity's calculated Facility Ratings do not reflect the FRM requirement, then the CEA is to find a non-compliance with FAC-009 R1. *See below for a discussion regarding compliance actions.*
- Additionally, where an entity's Facility Ratings include the FRM requirement, the Facilities are to be constructed to the actual clearances and/or design criteria specified in the entity's FRM. If the Facilities in the field are not constructed to design specifications and/or within acceptable tolerances for clearances, the CEA is to find a non-compliance with FAC-009 R1.

If the CEA determines that Option 2 applies, i.e. where clearances or design criteria are stated broadly as general policy requirements:

- A CEA is not to consider actual field construction in assessing compliance.

FAC-009 R2

FAC-009-1 R2 requires TOs and GOs to provide Facility Ratings for solely and jointly owned existing Facilities and new Facilities, as well as any modifications to existing Facilities or re-ratings of existing Facilities to their associated RCs, Planning Authorities (PA), Transmission Planners (TP), and TOPs as scheduled by such requesting entities.

FAC-009 provides, in pertinent part:

> ***R2.*** *The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.*

In assessing compliance with FAC-009-1 R2, a CEA is to verify that an entity provided its current Facility Ratings as scheduled by the requesting entities. As R2 includes "new Facilities, modifications to existing

Facilities and re-ratings of existing Facilities," a CEA is also to verify that TOs updated their ratings to address changing field conditions.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[4] a CEA is to apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

It is of prime importance that registered entities operate reliably within the requirements and assumptions that are contained in the registered entity's FRM. The Recommendation cited above addresses only the issue of whether Facilities were constructed pursuant to a registered entity's design specifications and required clearances.

During any finding of possible non-compliance, CEAs are to strongly consider a registered entity's concerns for reliability, such as when the entity included the actual physical application of their design criteria in the field for individual Facilities and/or actual clearances for individual Facilities in their FRMs. In the event a CEA determined that there are discrepancies between the design and actual field conditions that are outside the registered entity's design tolerances, the following will be strong considerations in the determination of a zero-dollar penalty or FFT resolution:

- the registered entity's continuation of its robust FRM;
- timely and thorough evaluations by the registered entity of its system using accurate measurement methods and technologies;
- timely self-disclosure of any compliance gaps; and
- prompt corrective actions and consistent completion of its Mitigation Plan milestones.

Further, CEAs are to exercise discretion to hold the processing of all possible violations reported as a result of the assessments until the entity's assessments are complete, as long as the registered entity reporting such possible violations is proceeding in good faith to complete the assessments.

[4] "Initiated" means that a registered entity has received notification of the upcoming audit.

Please note that in the unlikely circumstance that an actual event occurs in which a CEA determines a discrepancy between actual conditions and facility ratings was a cause or contributing factor, the CEA is to proceed to investigate that case directly and not wait. Similarly, any possible violations of FAC-003 should continue to be reported immediately and may be processed separately and immediately by the CEA.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
January 7, 2011	**Posted Final CAN**	
November 11, 2011	**Posted Revised CAN**	**Revised target audience to CEAs**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Style Definition: List Paragraph: Font: 12 pt, Indent: Left: -0.5", Position: Horizontal: Left, Relative to: Column, Vertical: In line, Relative to: Margin, Horizontal: 0", Wrap Around

Compliance Application Notice

~~Compliance Application:~~ FAC-008 and FAC-009 Facility Ratings and Design Specifications

Posted: January 7, 2011
Revised: November 11, 2011

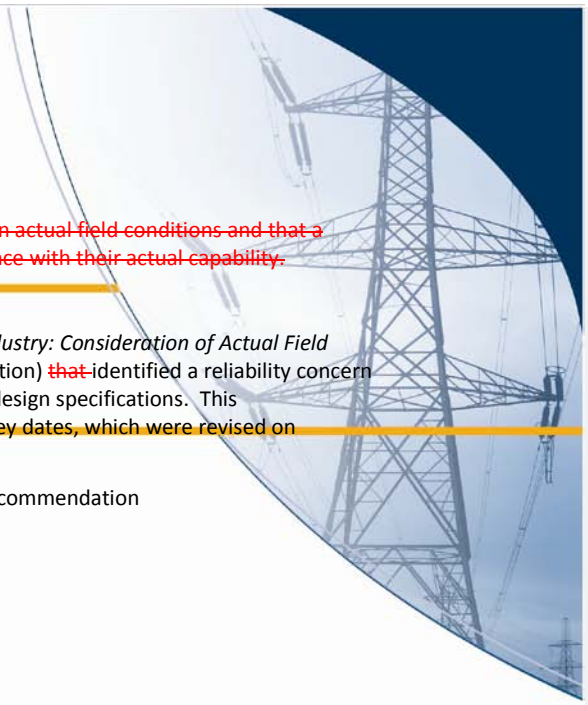
Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
Transmission Owner (TO)
Generation Owner (GO)
Regional Entity
NERC
~~Transmission Owners~~
~~Generation Owners~~

Issue: Should CEAs find a violation of FAC-008 R1 or FAC-009 when it is determined that constructed Facilities do not match design specifications?
For the purpose of aiding CEAs, this CAN provides instruction for assessing compliance with FAC-008 R1 and FAC-009 R1 when an entity's constructed Facilities do not match its design specifications.
~~**Constructed facilities not matching a registered entity's design specifications**~~
~~NERC Compliance received a request for clarification regarding whether registered entities should self-report a violation of either FAC-008-1 R1 or FAC-009-1 R1 when constructed Facilities do not match a registered entity's design specifications.~~

Summary
Due to the Recommendation to Industry (discussed below), possible non-compliances may be discovered for registered entities that had developed the most robust Facility Rating Methodologies (FRMs). This CAN reinforces the premise that the recommendation was based on improving reliability, not creating compliance enforcement actions. It also provides for these Possible Violations to be held in abeyance for determination after the registered entity's assessment is complete, with strong considerations for a zero-dollar penalty or resolution through the Find, Fix and Track (FFT) recording mechanism.
~~**Reliability Objective**~~

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

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



~~To ensure that a registered entity's Facility Ratings are based on actual field conditions and that a registered entity's Facilities are therefore operated in accordance with their actual capability.~~

Background

~~On October 7, 2010,~~ NERC's ~~issued the~~ *Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings*[2] (Recommendation) ~~that~~ identified a reliability concern due to Facilities in the field not matching a registered entity's design specifications. This Recommendation contained a call to action for industry with key dates, which were revised on November 29 as follows:

- October 20, 2010 – Acknowledge receipt of Recommendation
- October 28, 2010 – Attend Webinar (optional)
- November 29, 2010 – Attend second Webinar (optional)
- January 18, 2011– Assess impact of the alert and provide an action plan, as required, to NERC, including any extension requests for completing assessments (originally December 15, 2010)
- May 12, 2011 – Attend Webinar (optional)
- Complete assessments - Identify all discrepancies between the design and actual field conditions that are outside the registered entity's design tolerances and report those discrepancies to NERC, applicable Reliability Coordinators (RCs), Transmission Operators (TOPs), and Regional Entities by:[3]

~~• October 28, 2010 – attend Webinar (optional)~~

~~• November 29, 2010 – attend second Webinar (optional)~~

~~• January 18, 2011– assess impact of the alert and provide an action plan, as required, to NERC, including any extension requests for completing assessments (originally December 15, 2010)~~

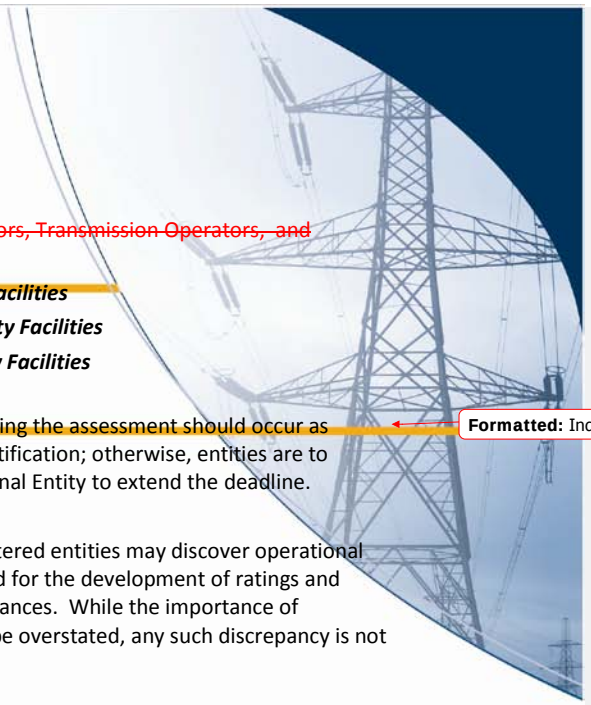
~~• Complete assessments - Identify all discrepancies between the design and actual field conditions that are outside the registered entity's design tolerances and report those~~

Formatted: Indent: Left: -0", Hanging: 0"

[2] Issued on October 7, 2010

[3] All assessments were originally due on April 7, 2011.

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



discrepancies to NERC, applicable Reliability Coordinators, Transmission Operators, and Regional Entities by (originally April 7, 2011):

1. ***December 31, 2011 for High Priority Facilities***
2. ***December 31, 2012 for Medium Priority Facilities***
3. ***December 31, 2013 for Lowest Priority Facilities***

- Remediation to correct all issues identified during the assessment should occur as quickly as practical but within one year of identification; otherwise, entities are to obtain an approval from their respective Regional Entity to extend the deadline.

Formatted: Indent: Left: 0.25"

In addressing this important reliability Recommendation, registered entities may discover operational Facilities with discrepancies between design specifications used for the development of ratings and actual field conditions that are outside the entity's design tolerances. While the importance of correcting these discrepancies within the above dates cannot be overstated, any such discrepancy is not necessarily a violation of the NERC Reliability Standards.

Nevertheless, such a discrepancy may contribute to a possible violation of one or more of the following requirements: FAC-008-1 R1 or FAC-009-1 R1 or R2, based on the facts and circumstances specific to each instance, as described below. NERC encourages each registered entity to closely examine its Facility Ratings methodology (FRM) required by FAC-008-1 R1 and the application of its FRM as required by FAC-009 R1 and R2 to determine if it is in compliance. Where the registered entity makes a determination that it is not compliant, the entity should self report to the appropriate Regional Entity.

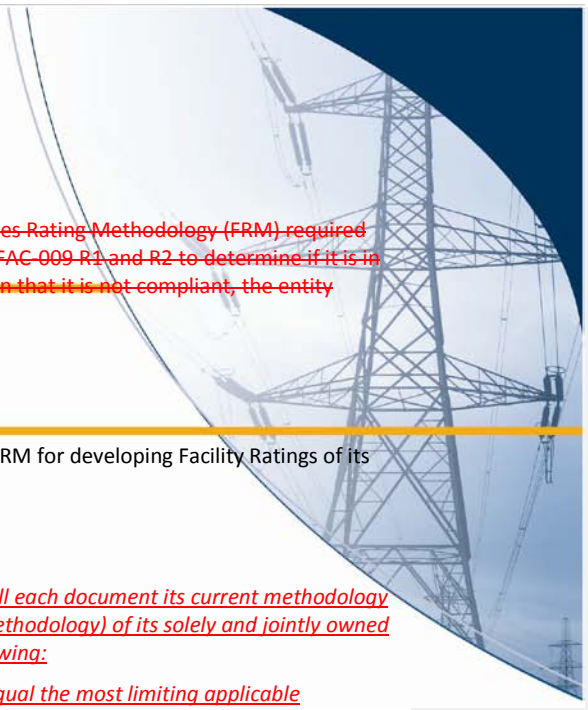
Compliance Application: FAC-008 and FAC-009

- Remediation to correct all issues identified during the assessment should occur as quickly as practical but within one year of identification OR obtain approval from NERC to extend deadline

In addressing this important reliability Recommendation, registered entities may discover operational Facilities with discrepancies between design specifications used for the development of ratings and actual field conditions that are outside the entity's design tolerances. While the importance of correcting these discrepancies within the above dates cannot be overstated, any such discrepancy is not necessarily a violation of the Reliability Standards.

Nevertheless, such a discrepancy may contribute to a possible violation of FAC-008-1 R1 or FAC-009-1 R1 or R2 based on the facts and circumstances specific to each instance, as described below. NERC

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



~~encourages each registered entity to closely examine its Facilities Rating Methodology (FRM) required by FAC-008-1 R1 and the application of its FRM as required by FAC-009 R1 and R2 to determine if it is in compliance. Where the registered entity makes a determination that it is not compliant, the entity should self report to the appropriate Regional Entity.~~

~~**Compliance Application**~~

FAC-008

FAC-008-1 requires a registered entity to have a documented FRM for developing Facility Ratings of its solely and jointly owned Facilities.

FAC-008 provides, in pertinent part:

> ***R1.*** *The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities. The methodology shall include all of the following:*
>
> > ***R1.1.*** *A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.*
> >
> > ***R1.2.*** *The method by which the Rating (of major BES equipment that comprises a Facility) is determined.*
> >
> > > ***R1.2.1.*** *The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.*
> > >
> > > ***R1.2.2.*** *The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.*
> >
> > ***R1.3.*** *Consideration of the following:*
> >
> > > ***R1.3.1.*** *Ratings provided by equipment manufacturers.*
> > >
> > > ***R1.3.2.*** *Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).*
> > >
> > > ***R1.3.3.*** *Ambient conditions.*
> > >
> > > ***R1.3.4.*** *Operating limitations.*
> > >
> > > ***R1.3.5.*** *Other assumptions.*

CEAs are to verify ~~thatwhether~~that a registered entity's FRM included consideration of the equipment manufacturer's provided ratings (R1.3.1), design criteria (R1.3.2), ambient conditions (R1.3.3), operating limitations (R1.3.4) and other assumptions (R1.3.5) in its FRM.
~~The methodology is to include consideration of the following:~~

~~R1.3.1. Ratings provided by equipment manufacturers.~~

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

~~R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).~~

~~R1.3.3. Ambient conditions.~~

~~R1.3.4. Operating limitations.~~

~~R1.3.5. Other assumptions.~~



Compliance Application: FAC-008 and FAC-009

Where an entity's FRM considered equipment manufacturer's provided ratings (R1.3.1), design criteria (R1.3.2), ambient conditions (R1.3.3), operating limitations (R1.3.4) and other assumptions (R1.3.5), the registered entity would be in compliance with FAC-008-1 R1.

FAC-009 R1

FAC-009-1 R1 requires TOs and GOs to establish Facility Ratings for their solely and jointly owned Facilities that are consistent with the associated FRM, which is required under FAC-008 R1.

FAC-009 provides, in pertinent part:

> ***R1.*** *The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology.*

~~FAC-009 R1~~

~~FAC-009-1 R1 requires each Transmission Owner and Generator Owner to establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated FRM.~~

Therefore, in order for a CEA to determine whether a registered entity's Facility Ratings were established pursuant to the entity's FRM, the CEA is to first verify whether the entity's FRM addresses design criteria for Transmission Facilities, including clearances, and if so, whether the design criteria and clearances that are included are:

~~In order to be compliant with FAC-009-1 R1, a registered entity's Facility Ratings must be established pursuant to its FRM required by FAC-008-1 R1.~~

~~In order to determine whether a registered entity's Facility Ratings were established pursuant to its FRM, a registered entity should first evaluate whether its FRM addresses design criteria for Transmission~~

Comment [A1]: Industry Comment:

There is no wording in FAC-008 or FAC-009 that identifies a violation if design information and field construction do not match. These words are not present in either standard or any of the requirements. NERC has incorrectly, through this CAN process created a new requirement which is explicitly forbidden by NERC's own Rules of Procedure and the CAN process.

Further the NERC Alert by definition is not law and cannot be the sole basis for an enforcement action.

Comment [A2]: See points one and two

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

~~Facilities, including clearances and, if so, whether the design criteria and clearances that are included are:~~

1) the actual physical application of the design criteria in the field for individual Facilities and/or actual clearances for individual Facilities; ***or***

2) did not include the actual physical application of the design criteria in the field for individual Facilities and/or actual clearances for individual Facilities. In this case, the entity may have stated design criteria broadly as general policy requirements.~~stated broadly as general policy requirements.~~

If the CEA determines that Option 1 applies, i.e. where an entity's FRM requires the inclusion of the actual clearances or the physical applications of design criteria in the field for individual Facilities in the calculation of the Facility Rating:

~~***Where an entity's FRM requires the inclusion of the actual clearances or the physical applications of design criteria in the field for individual Facilities in the calculation of the Facility's Rating (#1):***~~

- If the entity's calculated Facility Ratings do not reflect the FRM requirement, then the CEA is to find a non-compliance with FAC-009 R1. *See below for a discussion regarding compliance actions.*

- ~~If the entity's calculated Facility Ratings do not reflect the FRM requirement, then the registered entity would possibly be non-compliant with FAC-009 R1.~~

  - ~~Additionally, where an entity's Facility Ratings include the FRM requirement, the Facilities must be constructed to the actual clearances and/or design criteria specified in the entity's FRM. If the Facilities in the field are not constructed to design specifications and/or within acceptable tolerances for clearances, or the registered entity would possibly be non-compliant with FAC-009 R1.~~

- Additionally, where an entity's Facility Ratings include the FRM requirement, the Facilities are to be constructed to the actual clearances and/or design criteria specified in the entity's FRM. If the Facilities in the field are not constructed to design specifications and/or within acceptable tolerances for clearances, the CEA is to find a non-compliance with FAC-009 R1.

If the CEA determines that Option 2 applies, i.e. where clearances or design criteria are stated broadly

Comment [A3]: Industry Comment (EEI):

Penalizing entities that fall under Option 1, as indicated in the CAN, would incorrectly penalize entities who have included appropriate reliability measures in favor of those who were less specific. Furthermore, the simple identification of clearances as criterion in their FRM or even the validation of those clearances at the time of the original installation would not constitute a violation of the requirements of either standard or the entity's FRM unless the entity's FRM criteria also specifically required periodic inspections to validate those clearances over time and even in those situations, not all changes can be reasonably controlled over time.

Moreover, the situation is being addressed by NERC through two NERC Alerts, "Recommendations to the Industry" dated October 7, 2010 and updated on November 20, 2010. Therefore, we see no benefit to reliability through a punitive process that we believe is unenforceable. We also note that NERC, through the above mentioned Alerts, has already set a schedule for assessing facility conditions by priority. Those schedules through urgent Industry attention are being effectively addressed while issues, as they are uncovered, are being resolved. Consequently, EEI respectfully submit that this CAN should be rescinded or dismissed in its entirety.

Formatted: Default, Bulleted + Level: 1 + Aligned at: -0.25" + Indent at: 0"

Formatted: Default, No bullets or numbering

Formatted: Font: +Body, 11 pt

Formatted: Default, Space Before: 6 pt, Bulleted + Level: 1 + Aligned at: -0.25" + Indent at: 0"

Formatted: Font: +Body, 11 pt

Formatted: Font: +Body, 11 pt

Formatted: Font: Calibri, 11 pt, Italic

Formatted: Font: +Body, 11 pt

Formatted: Default, Indent: Left: 0", Adjust space between Latin and Asian text, Adjust space between Asian text and numbers

Formatted: Default, No bullets or numbering

Formatted: Font: +Body, 11 pt

Formatted: Font: +Body, 11 pt

Formatted: Font: 11 pt

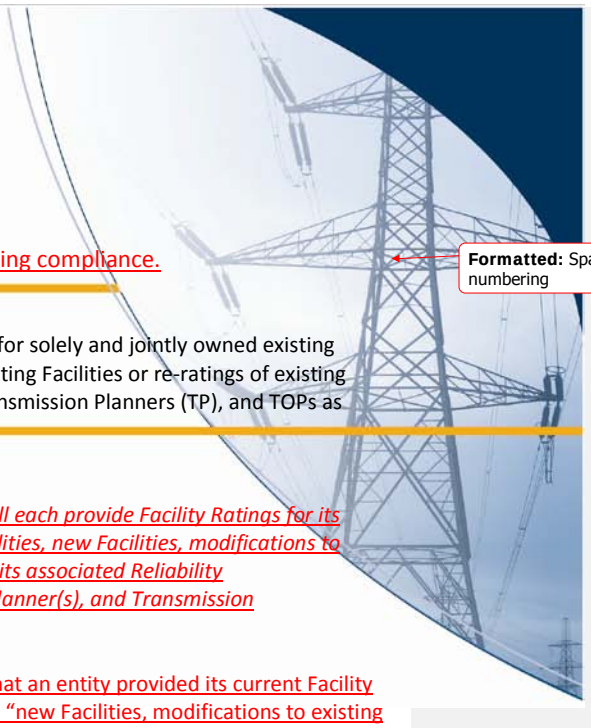
Formatted: Not Highlight

Comment [A4]: Industry Comment:

The CAN implies that the FRM can only fit into two categories: reflection of actual field conditions an ...

Comment [A5]: See additional language at point #2

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



as general policy requirements.

A CEA is not to consider actual field construction in assessing compliance.

Formatted: Space Before: 0 pt, No bullets or numbering

FAC-009 R2

FAC-009-1 R2 requires TOs and GOs to provide Facility Ratings for solely and jointly owned existing Facilities and new Facilities, as well as any modifications to existing Facilities or re-ratings of existing Facilities to their associated RCs, Planning Authorities (PA), Transmission Planners (TP), and TOPs as scheduled by such requesting entities.

FAC-009 provides, in pertinent part:

> ***R2.*** *The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.*

In assessing compliance with FAC-009-1 R2, a CEA is to verify that an entity provided its current Facility Ratings as scheduled by the requesting entities. As R2 includes "new Facilities, modifications to existing Facilities and re-ratings of existing Facilities," a CEA is also to verify that TOs updated their ratings to address changing field conditions.

Evidence of Compliance

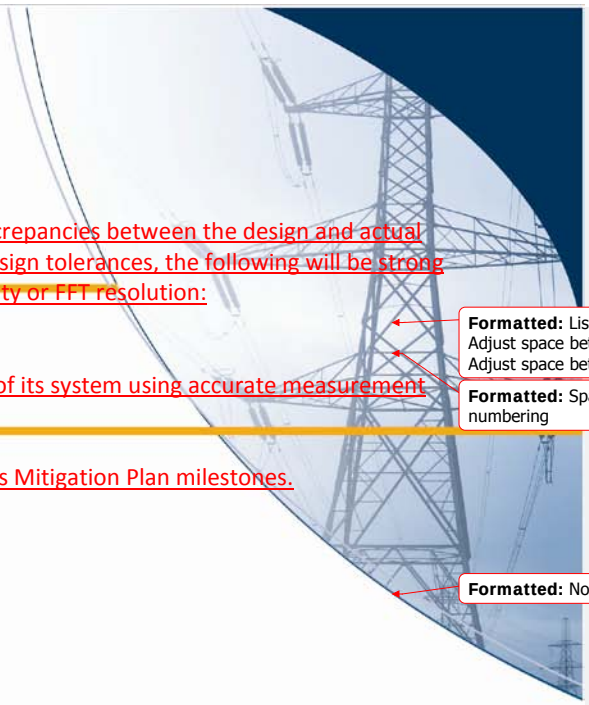
It is of prime importance that registered entities operate reliably within the requirements and or assumptions that are contained in the registered entity's FRM. The Recommendation cited above addresses only the issue of whether Facilities were constructed pursuant to a registered entity's design specifications and required clearances.

Formatted: Normal, No bullets or numbering

During any finding of possible non-compliance, CEAs are to strongly consider a registered entity's concerns for reliability, such as when the entity included the actual physical application of their design criteria in the field for individual Facilities and/or actual clearances for individual Facilities in their

Formatted: Indent: Left: 0"

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



FRMs. In the event a CEA determined that there are discrepancies between the design and actual field conditions that are outside the registered entity's design tolerances, the following will be strong considerations in the determination of a zero-dollar penalty or FFT resolution:

the registered entity's continuation of its robust FRM;
timely and thorough evaluations by the registered entity of its system using accurate measurement methods and technologies;
timely self-disclosure of any compliance gaps; and
prompt corrective actions and consistent completion of its Mitigation Plan milestones.

~~the registered entity's continuation of its robust FRM;~~

~~timely and thorough evaluations by the registered entity of its system using accurate measurement methods and technologies;~~
~~timely self-disclosure of any compliance gaps; and~~
~~prompt corrective actions and consistent completion of its Mitigation Plan milestones.~~

Further, CEAs are to exercise discretion to hold the processing of all possible violations reported as a result of the assessments until the entity's assessments are complete, as long as the registered entity reporting such possible violations is proceeding in good faith to complete the assessments.

Please note that in the unlikely circumstance that an actual event occurs in which a CEA determines a discrepancy between actual conditions and facility ratings was a cause or contributing factor, the CEA is to proceed to investigate that case directly and not wait. Similarly, any possible violations of FAC-003 should continue to be reported immediately and may be processed separately and immediately by the CEA.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from January 7, 2011. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

Formatted: List Paragraph, Indent: Left: 0", Adjust space between Latin and Asian text, Adjust space between Asian text and numbers

Formatted: Space Before: 0 pt, No bullets or numbering

Formatted: Normal, No bullets or numbering

Formatted: Font: (Default) Calibri, 11 pt

Formatted: Space Before: 0 pt, No bullets or numbering

Formatted: Font: (Default) Calibri, 11 pt

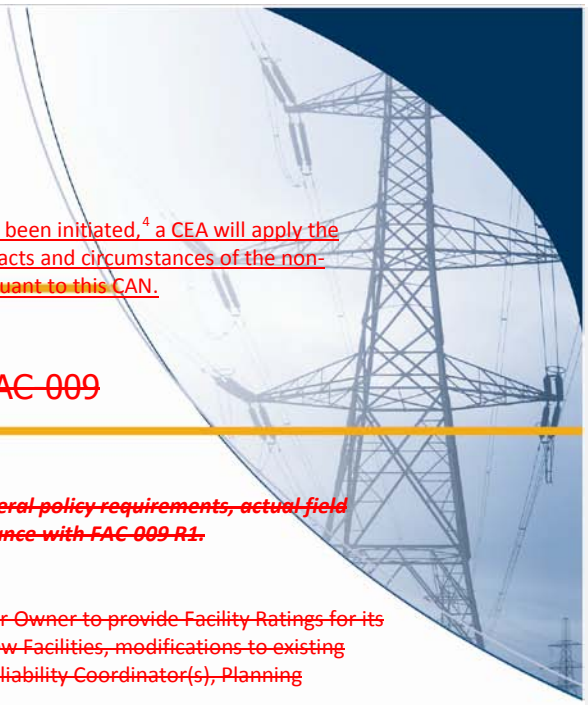
Comment [A6]: Industry comment (EEI):

EEI believes that NERC needs to incorporate a reasonable implementation period for all CANs. Generally, we have observed that CANs routinely apply either retroactive enforcement or enforcement from the point of "Final Posting".
In both cases, entities are not afforded any ability to adjust their programs, policies, systems or hardware to conform to these newly defined or clarified requirements. This approach, if left unchanged, will ensure that many, if not most, registered entities will be continually self reporting their potential noncompliance as a result of CANs. This situation is concerning and troubling particularly at a time when NERC is pursuing Find, Fix and Track.

Comment [A7]: Industry Comment:

This language is troubling given that the effective date authority is expressly provided for in the Reliability Standards. The proposed effective period in the CANs should not usurp this authority in any way. Once a future version of the Standard in question is approved and effective, judgment on whether the future version addresses the specific issue in the CAN is irrelevant in light of new Standard language and questions must be considered in the context of the newly applicable Standard language.

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



For any enforcement action in process and for audits that have been initiated,[4] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Compliance Application: FAC-008 and FAC-009

Where clearances or design criteria are stated broadly as general policy requirements, actual field construction would not considered in determining noncompliance with FAC-009 R1.

FAC-009 R2
FAC-009-1 R2 requires each Transmission Owner and Generator Owner to provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

For compliance with FAC-009-1 R2, an entity that provides its current Facility Ratings as scheduled by the requesting entities would be in compliance with the requirement. As R2 includes "new Facilities, modifications to existing Facilities and re-ratings of existing Facilities," the standard contemplates that transmission owners update their ratings to address changing field conditions and would thus be positioned for compliance with the standard.

Possible Compliance Actions
The first order of business under FAC-009 is for registered entities to operate reliably within the requirements and or assumptions contained in the registered entity's FRM.

In contrast, the Recommendation addresses whether Facilities were constructed pursuant to a registered entity's design specifications and required clearances.

Registered entities that included the actual physical application of its design criteria in the field for individual Facilities and/or actual clearances for individual Facilities in its FRM have exhibited an attention to detail and a concern for reliability. In the event a registered entity discovers a noncompliance as a result of this Recommendation, the a registered entity's continuation of its robust FRM; timely and thorough evaluations of its system using accurate measurement methods and technologies; timely self-disclosure of any compliance gaps; prompt corrective actions and consistent completion of its Mitigation Plan milestones will be strong considerations in the determination of a zero-dollar penalty.

[4] "Initiated" means that a registered entity has received notification of the upcoming audit.

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



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

~~Compliance Application: FAC-008 and FAC-009~~

~~Further, NERC and Regional Entity staff will exercise enforcement discretion to hold the processing of all possible violations reported as a result of the assessments until the entity's assessments are complete, as long as the registered entity reporting such possible violations is proceeding in good faith to complete the assessments.~~

~~Please note that in the unlikely circumstance that an actual event occurs in which NERC or the Regional Entity determines a discrepancy between actual conditions and facility ratings was a cause or contributing factor, then NERC or the Regional Entity would proceed to investigate that case directly and not wait. Similarly, any possible violations of FAC-003 should continue to be reported immediately and may be processed separately and immediately by the Regional Entity or NERC.~~

~~Prior Related Communications~~

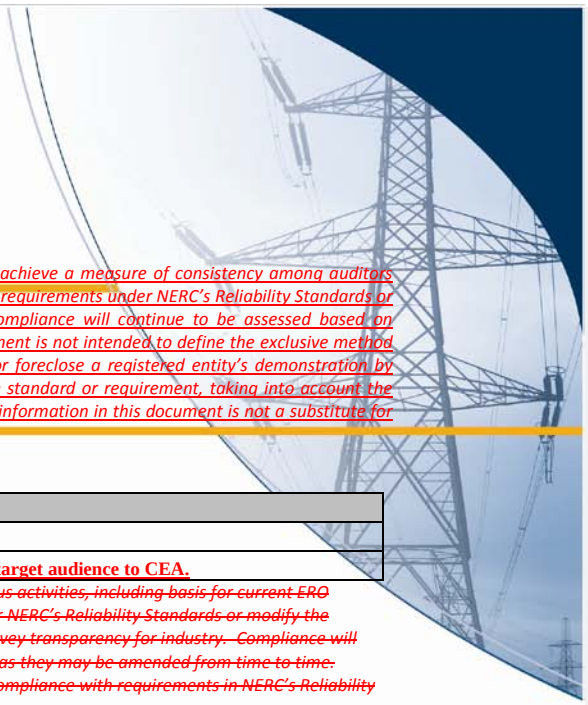
~~*FAC-008-1 RSAW November 2, 2009 – Facility Ratings Methodology~~
~~*FAC-009-1 RSAW November 2, 2009 – Establish and Communicate Facility Ratings~~
~~*Order 693, ¶ 736 - 771, March 16, 2007~~

For more information please contact:

Michael Moon
Director of Compliance Operations and Outreach
michael.moon@nerc.net
609-524-7028

Valerie Agnew
Manager of ~~Compliance Standards~~ Interface
valerie.agnew@nerc.net
609-524-7075

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



NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Posted Date	Action	Revision
January 7, 2011	Posted Final CAN	
November 11, 2011	Posted Revised CAN	Revised target audience to CEA.

~~*This document is designed to convey compliance guidance from NERC's various activities, including basis for current ERO enforcement determinations. It is does not establish new requirements under NERC's Reliability Standards or modify the requirements in any existing NERC Reliability Standard, but is intended to convey transparency for industry. Compliance will continue to be assessed based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this compliance application notice is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

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

Industry Comments for CAN-0009		
Comment Topics	**Main Points**	**Industry Suggestions**
Errata Changes	Need to list R1.3 in entirety	Spell out full standard
Scope	The CAN incorrectly implies that the requirement is to have the field conditions match the design.	There is no such requirement. The requirements are to have a FRM and apply that FRM to establish ratings.
Effective Date	This language is troubling given that the effective date authority is expressly provided for in the Reliability Standards. The proposed effective period in the CANs should not usurp this authority in any way.	The CAN Process language may need to address how final CANs are to be treated when further revised. When a once final CAN is selected for revision, it makes sense that it would be rescinded and replaced by the updated final CAN thus removing any standing of the former final CAN.
Evidence	The first paragraph should be struck. The statements are irrelevant, their purpose is not clear and the paragraph does not support evidence of compliance.	There is no recommended evidence for either the CEAs or registered entities to properly evaluate application or compliance with the standard. This section is more focused on enforcement action and penalty assessment and should not be part of this CAN. This entire section be revised to provide recommended evidence and not focus on enforcement actions or penalty assessments.
Process	Unreasonable pace that revising and reposting "all" CANs in 12 weeks presents. Previous requests were made for more time to review CANs posted for input, and while the time allowed increased from two weeks to three, increasing the number of CANs posted for review defeats the time added.	Due to such volume, NERC may not receive the constructive input from stakeholders that they could have under a more measured approach. Understanding that the current volume is a unique task resulting from Board direction, we are doing our best to review and comment on postings, and again we appeal for a more reasonable review opportunity going forward.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0017

CIP-007 R5 Technical and Procedural System Access and Password Controls

Posted: November 11, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Registered Entities subject to CIP Reliability Standards

Issue: Is a CEA to verify that technical controls, procedural controls, or both are implemented in assessing compliance with CIP-007[2] Requirement (R)5?

For the purpose of aiding a CEA, this CAN provides instruction for assessing whether a technical solution, a procedural solution or both are required for system access and password controls for a registered entity's Cyber Assets and Critical Cyber Assets to fulfill the requirements of CIP-007 R5.

- System Access Controls – R5, R5.1 and R5.2
  First, this CAN provides instruction regarding when a CEA is to verify technical or procedural controls under R5.1 and R5.2, which state that a registered entity will establish, implement, and document technical *and* procedural controls, noting that both are not applicable to each of the actions contained in the sub-requirements of R5.1 and R5.2.

- Administrator, Shared, or Other Generic Account Passwords – R5.2.1
  Second, this CAN clarifies that the passwords specified in R5.2.1 must comply with the password construction and change requirements contained in R5.3.

- Password Controls – R5.3
  Third, this CAN provides instruction regarding when a CEA is to verify that a registered entity has a fully compliant technical solution.[3]

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

[2] The FERC order approving the Version 2 CIP Reliability Standards, CIP-002-2 through CIP-009-2, was issued in September 2009. See North American Electric Reliability Corp., 128 FERC ¶ 61,291 (September 2009 Order), order denying rehearing and granting clarification, 129 FERC ¶ 61,236 (2009). The FERC Order on Version 3 CIP Reliability Standards was issued on March 31, 2010. See North American Electric Reliability Corp., 130 FERC ¶ 61,271 (2010) (March 31 Order).

[3] Registered entities' software, hardware and equipment have varying degrees of capability to provide a technical solution to fulfill the password control requirements of R5.3. Consequently, registered entities, under currently owned equipment, software, and security password schemes, may not have the ability to ensure compliance with the standard via a fully compliant technical solution.

- Technical Feasibility Exception (TFE)
  Finally, this CAN provides instruction on when a CEA is to verify the entity has submitted a request for a TFE and whether the TFE request has been approved.

Summary of Compliance Application Notice

A CEA is to verify that a registered entity has implemented technical and procedural controls as required in the standards. In regard to R5.3, when an entity's Cyber Asset or Critical Cyber Asset is not capable of structuring passwords as required by the standard, then the CEA is instructed to verify whether the asset is covered under a TFE or the safe harbor of a TFE submission. In the case of a TFE submission, the CEA is instructed to verify whether the TFE-based compensating measures are in place. If a registered entity has submitted a TFE request, the entity will be subject to a safe harbor pending approval of the TFE, pursuant to section 5.3 of appendix 4D of the NERC Rules of Procedure.

Background

CIP-007 provides, in pertinent part:

R5. *Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.*

R5.1. *The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.*

R5.1.1. *The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.*

R5.1.2. *The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.*

R5.1.3. *The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.*

R5.2. *The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.*

R5.2.1. *The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.*

R5.2.2. *The Responsible Entity shall identify those individuals with access to shared accounts.*

R5.2.3. *Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).*

R5.3. *At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:*

R5.3.1. *Each password shall be a minimum of six characters.*

R5.3.2. *Each password shall consist of a combination of alpha, numeric, and "special" characters.*

R5.3.3. *Each password shall be changed at least annually, or more frequently based on risk. [Emphasis added]*

Compliance Application

System Access Controls – R5, R5.1 and R5.2

NERC and the Regional Entities have determined that the "and" in R5 indicates that both technical and procedural controls are required throughout the sub-requirements R5.1 and R5.2, but both are not required for each of the actions required by R5.1 and R5.2. Therefore, a CEA is to verify that a registered entity has implemented the appropriate control(s) – either 1) both technical and procedural controls, or 2) only a procedural control – as required for each action. To clarify the first point, whenever a registered entity has a technical control, the technical control has been programmed to perform pursuant to a procedure, which is the procedural control. Therefore, whenever there is a technical control there is also an associated procedural control.

Examples:

R5.1.2 provides an example of a requirement where both procedural and technical controls are required. R5.2.1 requires an entity to establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails. Here, the methods, processes and procedures that generate the logs, to the extent they are electronic, would be a technical control. However, the entity also has a procedure that was programmed into the electronic solution that provides the procedural basis for the technical control and thus becomes the procedural control. A CEA is to verify the registered entity's technical control is performing as intended.

R5.1.3 provides an example of a requirement where only a procedural control is required. R5.1.3 requires an annual review of user accounts to verify access privileges. Here, the annual review to verify access privileges may be a manual process, and, if so, would be conducted pursuant to a procedural control. Because the standard only addresses the review, there would be no technical control required by R5.1.3. Note that the procedural control is associated with

a technical database or software program (an employee is reviewing the electronically generated audit trails).

Administrator, Shared, or Other Generic Account Passwords – R5.2.1

A CEA is to verify that passwords that were changed prior to putting the system into service (as required by R5.2.1) meet the password construction and maintenance controls of R5.3, specifically password length (R5.3.1), password complexity (R5.3.2), and periodic password change (R5.3.2). The CEA should review the initial password controls as it does any other password controls per R5.3, as discussed below. If any of these password controls cannot technically be met (either initially or when changed), the CEA is to verify whether the registered entity has requested or obtained a TFE.

Password Controls – R5.3

A CEA is to verify that a registered entity requires and uses passwords, subject to the sub-requirements of CIP-007 R5.3. Where a registered entity owns equipment that has the capability – to whatever degree – to provide a technical solution, the CEA is to verify that the registered entity has the technical solution enabled, regardless if the technical solution has the ability to meet all of the requirements of the standard, as outlined below:

1. **A technical solution is available:**
   If the software's technical solution fully meets the requirements of the standard, the CEA is to determine that the registered entity fulfills the requirement, and no further action is required.

   Example:

   A device supports at least six alphanumeric passwords (letters and numbers) and allows inclusion of special characters. If the device can be configured to require at least six characters in the password and can be configured to require letters, numbers and special characters, then there is a technical control and a procedural control, which would allow the registered entity to fulfill the requirements. For a CEA to find that the registered entity has met the requirements of R5.3.2 in this example, the CEA is to verify the registered entity implemented the technical control as specified in the procedural control.

2. **A technical control is available but does not fulfill the requirements of the standard:**
   If a registered entity has equipment for which a technical control only partially meets the requirements of the standard, but the equipment has the capability to fulfill all requirements of the standard by also implementing a procedural control for the remaining requirements, the CEA is to verify that the registered entity has implemented a procedural control for any requirements that the technical solution cannot fulfill, and has obtained, or is in the process of obtaining, a TFE.

Example:

The server or workstation at issue runs a software application that 1) can configure a minimum password length, 2) can require complex passwords, and 3) will accept a fully compliant password. However, while the minimum password length of six characters can be enforced, setting the complex password option does not prevent a complex password from *not* including either a numeric digit or a special character. In other words, the requirements of R5.3.1 can be met, but the requirements of R5.3.2 cannot. For a CEA to find that the registered entity has met the requirements of both R5.3.1 and R5.3.2 in this example, the CEA is to verify that the registered entity had enabled the technical solution (set the minimum password length to at least six and enabled the complex password option), had further augmented the technical controls with a procedural control by implementing an internal policy and training program that requires numeric and special characters for passwords, and had submitted a TFE for the technical component.

Whether a procedural control is adequate is determined through the evaluation and approval of a TFE; however, a sufficient procedural control could include a procedural policy statement, personnel training, and other compensating measures, such as requiring longer passwords, restricting electronic access, and having a more frequent password change cycle.[4]

3. **Neither a technical control nor a procedural control can be implemented on the targeted Cyber Asset or Critical Cyber Asset device that will fulfill the requirements of the standard:** If a registered entity has a device that is incapable of fulfilling the password requirements of the standard through a technical solution, a procedural solution or a combination of both, the CEA is to verify that the registered entity has requested or obtained a TFE.

   This situation may exist due to equipment restrictions for password lengths, equipment restricting the ability to change passwords, or password character sets not allowing the required diversity, among other reasons. The CEA is to verify that compensating technical or procedural controls are described in the TFE.

   Example:

   A piece of equipment can only support four numeric digits for a password. In this case, the device is not capable of configuring a compliant password at all. The registered entity can only rely upon procedural controls to require a four-digit password complexity; a six-character complex password is not possible. The CEA is not to find that the entity has met R5.3.2 in this example, and therefore is to verify that a TFE has been submitted.

[4] CIP-007 R5.3.3 requires each password to be changed at least annually or more frequently based on risk.

Effective Period for CAN

This CAN is effective for CIP-007 upon posting as final on the NERC Web site, and is to be used by CEAs to assess compliance from the posting date forward, regardless of the start date of any non-compliance or Possible Violation. It supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[5] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

System Access Controls – R5, R5.1 and R5.2

A CEA is to verify that a registered entity implemented either 1) both a technical and a procedural control, or 2) only a procedural control, for each action required by R5.1 and R5.2 by reviewing:

1. documentation of the control(s) the registered entity has implemented for each required action; and
2. evidence that the control(s) fulfill the requirement of the specific action.

Administrator, Shared, or Other Generic Account Passwords – R5.2.1

A CEA is to verify evidence of the password change as described in the discussion of R3.

Password Controls – R5.3

1. **A technical solution is available:**
   If the software's technical solution fully meets the requirements of the standard, a CEA is to review the registered entity's evidence demonstrating how its technical solution fulfills the requirements of R5.3.

2. **A technical control is available but does not fulfill the requirements of the standard:**
   Where a registered entity's technical solution does not have the ability to fully meet the requirements of R5.3, a CEA is to verify that the registered entity 1) provided a procedural solution for any requirements that its technical solution cannot fulfill and 2) has obtained, or is in the process of obtaining, an approved TFE.[6] Additionally, the CEA is instructed to review:
   a. the entity's approved TFE or submitted TFE request;
   b. evidence of the extent to which the entity's technical solution fulfills the requirement(s);
   c. documentation of the registered entity's procedural solution to meet the remaining requirements of R5.3;

[5] "Initiated" means that a registered entity has received notification of the upcoming audit.

[6] If a registered entity has submitted a TFE request, the entity will be subject to a safe harbor pending approval of the TFE, pursuant to section 5.3 of appendix 4D of the NERC Rules of Procedure.

d. documentation of the registered entity's training program to educate its affected personnel on its procedural solution as required by CIP-004; and
e. attestations from persons with overall responsibility for the procedural control (or alternative language: "attestations from persons responsible for implementing and/or overseeing compliance with the procedural solution").

3. **Neither a technical solution nor a procedural solution can be implemented on the targeted Cyber Asset or Critical Cyber Asset device:**
   If the registered entity cannot implement a technical solution or a procedural solution on the Cyber Asset or Critical Cyber Asset, a CEA is to verify that the registered entity has obtained, or is in the process of obtaining, a TFE.[7] Additionally, the CEA is instructed to review:
   a. the entity's approved TFE or submitted TFE request, and
   b. evidence of its implementation of the compensating measures (which may be on a different device) provided in its TFE.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

[7] *See* footnote 6.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0017 Comment Analysis Summary

CIP-007 R5 Technical and Procedural System Access and Password Controls

CAN-0017 provides instruction for assessing whether a technical solution, a procedural solution or both are required for system access and password controls for a registered entity's Cyber Assets and Critical Cyber Assets to fulfill the requirements of CIP-007 R5. The draft CAN was posted for industry comment on the NERC web site on September 23, 2011 and the comment period expired on October 14, 2011.

NERC received approximately 23 comments from various industry stakeholders and trade associations, which are identified below. The main themes of the comments consisted of the following four categories: errata changes, scope, effective date and evidence of compliance.

Errata

Errata changes were made in order to correct a few typos and to change the number of a footnote.

Scope

There two industry groups that recommended substantive changes to the CAN in regard to scope. There were several comments that stated a procedural control is permitted by the standards and a TFE should not be required. It is understood that the compliance application may generate additional TFE's when the TFE is process is already overburdened, however, after legal review, it was determined that the compliance application stated in the CAN is required by FERC Orders. [1]

R5 specifies the need for technical and procedural controls. R5.1 does not use the words "where technically feasible"[2] and thus a TFE is not required where a procedural solution is the appropriate solution. R5.2 also does not use the words "where technically feasible" so again, a TFE is not required nor available. In the case of R5.2.1, the CAN provides for the availability of a TFE as the passwords must be changed in accordance with R5.3. R5.3 requires and provides for the availability of a TFE.

Additionally, a comment was made in regards to the CEA verifying the adequacy of the controls submitted in the TFE, specifically that this is not the role of the CEA. The CAN was modified to remove the instruction that CEAs are to verify the adequacy of compensating measures.

[1] *See* 133 FERC ¶61,008, Order on Compliance Filing Docket No. RR10-1-001 (October 1, 2020) and NERC Rules of Procedure Appendix 4D.
[2] *Id.*

Effective Date

Several commenters believe that NERC should to incorporate a reasonable implementation period for CAN-0017 to allow for time to file a Technical Feasibility Exception (TFE) with the applicable Regional Entity.

In response, CAN-0017 is effective for CIP-007 R5 upon posting as final on the NERC Web site. Registered entities should be aware that auditors will be using the guidance in CAN-0017 for assessing compliance from the posted date going forward, however a submitted TFE will provide a safe harbor until the TFE is approved. Additionally, CEAs will use discretion in whether the CAN is to be applied to any entity who has received notification of an upcoming audit.

Evidence

Commenters had questions regarding the Evidence of Compliance section. Particularly, several industry members stated that the standard did not reference training and there is not an obligation to provide training under CIP-007 R5.

In response, the evidence listed in the CAN includes several options that CEA staff can look for to verify compliance with the standard. One of the key concerns was CEAs verifying evidence of training. Although CEAs are not to verify adequacy of compensating measures as compensating measures are to be evaluated through the TFE process, a CEA does need to verify that the compensating measures have been implemented. Training is one way to ensure that an entity's staff is aware of the procedural control. Training may be conducted in a variety of methods and evidence of such training may include interviews with the applicable personnel. Additionally, the Evidence of Compliance section states, "may include but is not limited to," to account for the fact that entities may or may not have a specific type of evidence.

Conclusion

The analysis spreadsheet for CAN-0017 is also posted on the NERC website. While the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments, it is hoped that this document will supplement that information. Feedback from all sources is key and NERC staff thanks industry for the time and effort put into providing that feedback. If you would like further discussion on CAN-0017, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
Ameren Services
American Electric Power (AEP)
Arizona Public Service (AZPS)

Bonneville Power Administration (BPA)
Constellation Energy (CEG)
Dominion Resources Services, Inc.
Epoch Technical Solutions
ITC Holdings
Kansas City Power & Light (KCP&L)
LG&E and KU Energy
Madison Gas and Electric (MGE)
MidAmerican Energy Company
PacifiCorp
Pepco Holdings, Inc.
PGN
PPL Electric Utilities
Southern Company
Westar Energy
Xcel Energy

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
National Rural Electric Cooperative Association (NRECA)
ISO/RTO Council Standards Review Committee (IRC SRC)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Compliance Application Notice — 0017

CIP-007 R5 Technical and Procedural System Access and Password Controls

Posted [DATE]

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entities
Registered Entities subject to CIP Reliability Standards

Issue: Is a CEA is to verify that technical controls, procedural controls, or both are implemented in assessing compliance with CIP-007[2] Requirement (R)-5?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether a technical solution, a procedural solution or both are required for system access and password controls for a registered entity's Cyber Assets and Critical Cyber Assets to fulfill the requirements of CIP-007 R5.

- System Access Controls – R5, R5.1 and R5.2
  First, this CAN provides instruction regarding when a CEA is to verify technical or procedural controls under R5.1 and R5.2, which state~~s~~ that a registered entity will establish, implement, and document technical *and* procedural controls, noting that both are not applicable to each of the actions contained in the sub-requirements of R5.1 and R5.2.

- Administrator, Shared, or Other Generic Account Passwords – R5.2.1
  Second, this CAN clarifies that the passwords specified in R5.2.1 must comply with the password construction and change requirements contained in R5.3.

- Password Controls – R5.3
  Third, this CAN provides instruction regarding when a CEA is to verify that a registered entity has a fully compliant technical solution.[3]

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards and requirements.
[2] The FERC order approving the Version 2 CIP Reliability Standards, CIP-002-2 through CIP-009-2, was issued in September 2009. *See North American Electric Reliability Corp.*, 128 FERC ¶ 61,291 (September 2009 Order), *order denying rehearing and granting clarification*, 129 FERC ¶ 61,236 (2009). The FERC Order on Version 3 CIP Reliability Standards was issued on March 31, 2010. *See North American Electric Reliability Corp.*, 130 FERC ¶ 61,271 (2010) (March 31 Order).
[3] Registered entities' software, hardware and equipment have varying degrees of capability to provide a technical solution to fulfill the password control requirements of R5.3. Consequently, registered entities, under currently owned equipment,

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

DRAFT

- Technical Feasibility Exception (TFE)
  Finally, this CAN provides instruction on when a CEA is to verify the entity has submitted a request for a TFE and whether the TFE request has been approved.

~~CAN~~ Summary of Compliance Application Notice

Formatted: Font: Bold

A CEA is to verify that a registered entity has implemented technical and procedural controls as required in the standards. In regard to R5.3, when an ~~entities'~~ entity's Cyber Asset or Critical Cyber Asset is not capable of structuring passwords as required by the standard, then the CEA is instructed to verify whether the asset is covered under a TFE or the safe harbor of a TFE submission. In the case of a TFE submission, the CEA is instructed to verify whether the TFE-based compensating measures are in place. ~~there are adequate compensating measures in place.~~ If a registered entity has submitted a TFE request, the entity will be subject to a safe harbor pending approval of the TFE, pursuant to section 5.3 of appendix 4D of the NERC Rules of Procedure.

Background

CIP-007 provides, in pertinent part:

> ***R5.*** *Account Management — The Responsible Entity shall establish, implement, and document technical and procedural controls that enforce access authentication of, and accountability for, all user activity, and that minimize the risk of unauthorized system access.*
>
> ***R5.1.*** *The Responsible Entity shall ensure that individual and shared system accounts and authorized access permissions are consistent with the concept of "need to know" with respect to work functions performed.*
> ***R5.1.1.*** *The Responsible Entity shall ensure that user accounts are implemented as approved by designated personnel. Refer to Standard CIP-003-3 Requirement R5.*
> ***R5.1.2.*** *The Responsible Entity shall establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails of individual user account access activity for a minimum of ninety days.*
> ***R5.1.3.*** *The Responsible Entity shall review, at least annually, user accounts to verify access privileges are in accordance with Standard CIP-003-3 Requirement R5 and Standard CIP-004-3 Requirement R4.*
>
> ***R5.2.*** *The Responsible Entity shall implement a policy to minimize and manage the scope and acceptable use of administrator, shared, and other generic account privileges including factory default accounts.*
> ***R5.2.1.*** *The policy shall include the removal, disabling, or renaming of such accounts where possible. For such accounts that must remain enabled, passwords shall be changed prior to putting any system into service.*
> ***R5.2.~~1~~2.*** *The Responsible Entity shall identify those individuals with access to shared accounts.*

software, and security password schemes, may not have the ability to ensure compliance with the standard via a fully compliant technical solution.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

R5.2.~~1~~3. *Where such accounts must be shared, the Responsible Entity shall have a policy for managing the use of such accounts that limits access to only those with authorization, an audit trail of the account use (automated or manual), and steps for securing the account in the event of personnel changes (for example, change in assignment or termination).*

R5.3. *At a minimum, the Responsible Entity shall require and use passwords, subject to the following, as technically feasible:*

R5.3.1. *Each password shall be a minimum of six characters.*

R5.3.2. *Each password shall consist of a combination of alpha, numeric, and "special" characters.*

R5.3.3. *Each password shall be changed at least annually, or more frequently based on risk. [Emphasis added]*

Compliance Application

System Access Controls – R5, R5.1 and R5.2

NERC and the Regional Entities have determined that the "and" in R5 indicates that both technical and procedural controls are required throughout the sub-requirements R5.1 and R5.2, but both are not required for each of the actions required by R5.1 and R5.2. Therefore, a CEA is to verify that a registered entity has implemented the appropriate control(s) – either 1) both technical and procedural controls, or 2) only a procedural control – as required for each action. To clarify the first point, whenever a registered entity has a technical control, the technical control has been programmed to perform pursuant to a procedure, which is the procedural control. Therefore, whenever there is a technical control there is also an associated procedural control.

Examples

R5.1.2 provides an example of a requirement where both procedural and technical controls are required. R5.2.1 requires an entity to establish methods, processes, and procedures that generate logs of sufficient detail to create historical audit trails. Here, the methods, processes and procedures that generate the logs, to the extent they are electronic, would be a technical control. However, the entity also has a procedure that was programmed into the electronic solution that provides the procedural basis for the technical control and thus becomes the procedural control. A CEA is to verify the registered entity's technical control is performing as intended. ~~Additionally, the registered entity will also have a procedure to input data and generate reports, which is another procedural control.~~

R5.~~3~~1.3.~~1~~ provides an example of a requirement where only a procedural control is required. R5.~~3.1~~1.3 requires an annual review of user accounts to verify access privileges. Here, the annual review to verify access privileges may be a manual process, and, if so, would be conducted pursuant to a procedural control. Because the standard only addresses the review, there would be no technical control required by R5.3.1. Note that the procedural control is associated with a technical database or software program (an employee is reviewing the electronically generated audit trails).

Administrator, Shared, or Other Generic Account Passwords – R5.2.1

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

A CEA is to verify that passwords that were changed prior to putting the system into service (as required by R5.2.1) meet the password construction and maintenance controls of R5.3, specifically password length (R5.3.1), password complexity (R5.3.2), and periodic password change (R5.3.2). The CEA should review the initial password controls as it does any other password controls per R5.3, as discussed below. If any of these password controls cannot technically be met (either initially or when changed), the CEA is to verify whether the registered entity has requested or obtained a TFE.

Password Controls – R5.3

A CEA is to verify that a registered entity requires and uses passwords, subject to the sub-requirements of CIP-007 R5.3. Where a registered entity owns equipment that has the capability – to whatever degree – to provide a technical solution, the CEA is to verify that the registered entity has the technical solution enabled, regardless if the technical solution has the ability to meet all of the requirements of the standard, as outlined below:

1. **A technical solution is available:**
   If the software's technical solution fully meets the requirements of the standard, the CEA is to determine that the registered entity fulfills the requirement, and no further action is required.
   Example:
   A. ~~**Fully Compliant Procedural and Technical Solution:** -~~ A device supports at least six alphanumeric passwords (letters and numbers) and allows inclusion of special characters. If the device can be configured to require at least six characters in the password and can be configured to require letters, numbers and special characters, then there is a technical control and a procedural control, which would allow the registered entity to fulfill the requirements. For a CEA to find that the registered entity has met the requirements of R5.3.2 in this example, the CEA is to verify the registered entity implemented the technical control as specified in the procedural control.

2. **A technical control is available but does not fulfill the requirements of the standard:** ~~–~~
   If a registered entity has equipment for which a technical control only partially meets the requirements of the standard, but the equipment has the capability to fulfill all requirements of the standard by also implementing a procedural control for the remaining requirements, the CEA is to verify that the registered entity has implemented a procedural control for any requirements that the technical solution cannot fulfill, and has obtained, or is in the process of obtaining, a TFE.
   Example:

   ~~***Examples***~~
   ~~1.~~A. ~~**Fully Compliant Procedural and Technical Solution:** - A device supports at least six alphanumeric passwords (letters and numbers) and allows inclusion of special characters. If the device can be configured to require at least six characters in the password and can be configured to require letters, numbers and special characters, then there is a technical control and a procedural control, which would allow the registered entity to fulfill the requirements. For a CEA to find that the registered entity has met the requirements of R5.3.2 in this~~

Formatted: Indent: Left: 0.5"
Formatted: Font: 11 pt

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

~~example, the CEA is to verify the registered entity implemented the technical control as specified in the procedural control.~~

~~The server or workstation at issue runs a software application that 1) can configure a minimum password length, 2) can require complex passwords and 3) will accept a fully compliant password. However, while the minimum password length of six characters can be enforced, setting the complex password option does not prevent a complex password from not including either a numeric digit or a special character. In other words, the requirements of R5.3.1 can be met, but the requirements of R5.3.2 cannot. For a CEA to find that the registered entity has met the requirements of both R5.3.1 and R5.3.2 in this example, the CEA is to verify that the registered entity had enabled the technical solution (set the minimum password length to at least 6 six and enabled the complex password option), had further augmented the technical controls with a procedural control by implementing an internal policy and training program that requires numeric and special characters for passwords, and had submitted a TFE.~~

~~2.~~B. ~~**Fully Compliant Procedural cSolution:**~~ The server or workstation at issue runs a software application that 1) can configure a minimum password length, 2) can require complex passwords and 3) will accept a fully compliant password. However, while the minimum password length of six characters can be enforced, setting the complex password option does not prevent a complex password from *not* including either a numeric digit or a special character. In other words, the requirements of R5.3.1 can be met, but the requirements of R5.3.2 cannot. For a CEA to find that the registered entity has met the requirements of both R5.3.1 and R5.3.2 in this example, the CEA is to verify that the registered entity had enabled the technical solution (set the minimum password length to at least six and enabled the complex password option), had further augmented the technical controls with a procedural control by implementing an internal policy and training program that requires numeric and special characters for passwords, and had submitted a TFE for the technical component.

Formatted: Font: Italic

~~A device supports at least six alphanumeric passwords (letters and numbers) and allows inclusion of special characters but does not mandate the use of special characters. If the device can be configured to require at least six characters in the password and can be configured to require both letters and numbers, then there is a partial technical control, but a procedural control to include special characters, would require a procedural control to include special characters, which would allow the registered entity to fulfill the requirements. For a CEA to find that the registered entity has met the requirements of R5.3.2 in this example, the CEA is to verify the registered entity implemented the partial technical control, and submitted a TFE explaining additional (perhaps on a different device[4]) technical and procedural controls used.~~

~~C. **Non-Compliant Solution:** A server or workstation runs a software application that 1) can configure minimum password length, but the password cannot contain any~~

Formatted: Font: 11 pt

~~[4] In this case, additional technical and procedural controls might involve a "front-end processor" device which can be inserted into the communication path to technically enforce the password requirements, and a procedural control that requires use of the front-end device. Additional controls may be required for physical access.~~

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

~~special characters. The CEA cannot find that the entity has met R5.3.2 in this example, and therefore verify that a TFE has been submitted.~~

Whether a procedural control is adequate is determined through the evaluation and approval of a TFE; however, a sufficient procedural control could include a procedural ~~CEA is to look for a sufficient procedural control to include a compliant~~ policy statement, personnel training, and other compensating measures, such as requiring longer passwords, restricting electronic access, and a more frequent password change cycle.[5]

3. **Neither a technical control nor a procedural control can be implemented on the targeted Cyber Asset or Critical Cyber Asset device that will fulfill the requirements of the standard:** If a registered entity has a device that is incapable of fulfilling the password requirements of the standard through a technical solution, a procedural solution or a combination of both, the CEA is to verify that the registered entity has requested or obtained a TFE.

   This situation may exist due to equipment restrictions for password lengths, equipment restricting the ability to change passwords, or password character sets not allowing the required diversity, among other reasons. The CEA is to verify that compensating technical or procedural controls are described in the TFE.

   Example:
   A piece of equipment can only support four numeric digits for a password. In this case, the device is not capable of configuring a compliant password at all. The registered entity can only rely upon procedural controls to require a four-digit password complexity; a six-character complex password is not possible. The CEA is not to find that the entity has met R5.3.2 in this example, and therefore is to verify that a TFE has been submitted.

Effective Period for CAN
This CAN is effective for CIP-007 upon posting as final on the NERC Web site, and is to be used by CEAs to assess compliance from the posting date forward, regardless of the start date of any non-compliance or Possible Violation. It supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[6] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

~~Providing~~ Evidence of Compliance
System Access Controls – R5, R5.1 and R5.2
A CEA is to verify that a registered entity implemented either 1) both a technical and a procedural control, or 2) only a procedural control, for each action required by R5.1 and R5.2 by reviewing:

[5] CIP-007 R5.3.3 requires each password to be changed at least annually or more frequently based on risk.
[6] "Initiated" means that a registered entity has received notification of the upcoming audit.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

1. documentation of the control(s) the registered entity has implemented for each required action; and
2. evidence that the control(s) ~~are~~ fulfill~~ing~~ the requirement of the specific action.

Administrator, Shared, or Other Generic Account Passwords – R5.2.1
A CEA is to verify evidence of the password change as described in the discussion of R3.

Password Controls – R5.3

1. **A technical solution is available:**
   If the software's technical solution fully meets the requirements of the standard, a CEA is to review the registered entity's evidence demonstrating how its technical solution fulfills the requirements of R5.3.

2. **A technical control is available but does not fulfill the requirements of the standard:**
   Where a registered entity's technical solution does not have the ability to fully meet the requirements of R5.3, a CEA is to verify that the registered entity 1) provided a procedural solution for any requirements that its technical solution cannot fulfill and 2) has obtained, or is in the process of obtaining, an approved TFE.[7] Additionally, the CEA is instructed to review:
   a. the entity's approved TFE or submitted TFE request;
   b. evidence of the extent to which the entity's technical solution fulfills the requirement(s);
   c. documentation of the registered entity's procedural solution to meet the remaining requirements of R5.3;
   d. documentation of the registered entity's training program to educate its affected personnel on its procedural solution as required by CIP-004; and
   e. attestations from persons with overall responsibility ~~responsible~~ for the procedural control (or alternative language: "attestations from persons responsible for implementing and/or overseeing compliance~~ying~~ with the procedural solution").

3. **Neither a technical solution nor a procedural solution can be implemented on the targeted Cyber Asset or Critical Cyber Asset device:**
   If the registered entity cannot implement a technical solution or a procedural solution on the Cyber Asset or Critical Cyber Asset, a CEA is to verify that the registered entity has obtained, or is in the process of obtaining a TFE.[8] ~~.~~ Additionally, the CEA is instructed to review:
   a. the entity's approved TFE or submitted TFE request, and
   b. evidence of its implementation of the compensating measures (which may be on a different device) provided in its TFE.

For more information please contact:

Michael Moon
Director of Compliance Operations

Valerie Agnew
Manager of Interface and Outreach

[7] If a registered entity has submitted a TFE request, the entity will be subject to a safe harbor pending approval of the TFE, pursuant to section 5.3 of appendix 4D of the NERC Rules of Procedure.
[8] *See* footnote ~~8~~7.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

Michael.moon@nerc.net
404-446-2567

Valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

Industry Comments for CAN-0017

Comment Topics	Main Points	Industry Suggestions
Errata Changes	Typos and incorrect references to subrequirements	Fix the typos and incorrect numbering in the standard.
Scope	Exceeds the scope or adds new requirements to the standards.	CAN-0017 requires the CEA and the Responsible Entity to take actions above and beyond the requirement of Standard CIP-005 R5.3.
Effective Date	NERC implement a reasonable implementation period where Entities are afforded the ability to adjust their programs, policies, systems, or hardware to conform to newly defined or clarified requirements.	NERC needs to incorporate a reasonable implementation period for all CANs.
Evidence	Instruction that CEAs are to review “attestations from persons responsible for implementing and/or complying with the procedural solution” is not in line with the plain language of the approved standard.	The plain language of the standards and associated requirements as identified above simply do not specify training. Hence, training of the type and as identified is not required and should be stricken from the CAN.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0018 Comment Analysis Summary

FAC-008 Terminal Equipment

CAN-0018 provides instruction for assessing what equipment should be considered "terminal equipment" under FAC-008 R1.2.1. The CAN was posted for industry comment on the NERC web site on September 1, 2011 and the comment period expired on September 21, 2011.

NERC received approximately 20 comments from various industry stakeholders and trade associations, which are identified by name below. The main themes of the comments consisted of the following four categories: errata changes, the scope of the CAN and the effective date language.

Errata

The recommended errata changes were revised in order to provide clarity in the CAN.

Scope

There were several recommended substantive changes to the CAN in regard to the scope of the compliance guidance. The commenters stated that CAN-0018 expands the requirement by listing additional equipment that is not listed in the standard. Industry suggestions were that registered entities should be allowed to define what terminal equipment means in their Facility Rating methodology (FRM) and should not be limited to the direction of the CAN. While NERC understands the need for flexibility, in order to ensure that Compliance Enforcement Authority (CEA) staff applies FAC-008 consistently across the ERO, instruction for CEAs was needed. In response to some concerns that the equipment listed became too broad, the CAN was revised to state "the focus is on series-connected equipment that could have the most limiting applicable Equipment Rating".

In response to other comments, a footnote was added to clarify that Current Transformers (CTs) may be assessed as a Protection System element under relay protective devices, terminal equipment, or both categories listed in Requirement R1.2.1 depending upon the entity's FRM. (*See* footnote 2 in the CAN)

Effective Date

There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version. Several commenters believe that NERC should to incorporate a reasonable implementation period for CAN-0018. Other commenters suggested that a CAN should become effective only after it is posted as final and effective date cannot be earlier than the posted date.

To clarify the effective date in CAN-0018, which is June 17, 2011, the effective date remains the same date as the original posting. Because the change to the CAN materially revised the compliance application in the previously posted version by changing potential transformers to current transformers, the CEAS should apply the compliance application beginning on June 17, 2011 so there is no confusion regarding any potential application of the original CAN.

Conclusion

The analysis spreadsheet for CAN-0018 is also posted on the NERC website. While the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments, it is hoped that this document will supplement that information. Feedback from all sources is key and NERC staff thanks industry for the time and effort put into providing that feedback. If you would like further discussion on CAN-0018, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
Associated Electric Cooperative, Inc., Basin Electric Power Cooperative, Inc., and Tri-State Generation and Transmission Association, Inc
Bonneville Power Administration (BPA)
Constellation Energy (CEG)
Dominion Resources Services, Inc.
Farmington Electric Utility
Florida Municipal Power Authority (FMPA)
Indiana Municipal Power Agency
Kansas City Power & Light (KCP&L)
Liberty Electric Power
MidAmerican Energy Company
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
Public Service Electric and Gas (PSEG)
Southern Company
Westar Energy
Xcel Energy

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
ISO/RTO Council's Standard Review Committee (IRC SRC)
National Rural Electric Cooperative Association (NRECA)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0018

FAC-008 R1.2.1 Terminal Equipment

Posted: June 17, 2011
Reposted: November 11, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Transmission Owner (TO)
Generator Owner (GO)

Issue: What equipment is included under the term "terminal equipment" in the NERC Reliability Standard FAC-008?
For the purpose of aiding a CEA, this CAN provides instruction for assessing what equipment should be considered "terminal equipment" under FAC-008.

Background

Standard FAC-008 does not outline what equipment is classified as "terminal equipment" under R1.2.1.

The original CAN-0018 included all equipment that is generally deemed to be "terminal equipment." However, equipment such as potential devices that are not connected in series and, therefore, cannot limit a Facility Rating are not applicable to this requirement. CAN-0018 has been revised from the original posting of the final CAN to reflect only series connected terminal equipment that is applicable to FAC-008.

Compliance Application

FAC-008 provides, in pertinent part:

> ***R1.2.1.*** *The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.*

For the purpose of documenting the methodology used for developing Facility Ratings under FAC-008, the focus is on series-connected equipment that could have the most limiting applicable Equipment Rating.

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards or requirements.

CEAs are instructed to verify that a registered entity has included the following equipment as "terminal equipment" under FAC-008 R1.2.1:

- Wave traps
- Current transformers[2]
- Disconnect switches
- Breakers
- Primary fuses
- Any piece of series-connected equipment that comprises a Facility and that could have the most limiting applicable Equipment Rating

In the event an entity does not include a rating methodology for one or more of the above listed equipment types, a CEA is to verify that the entity does not own such equipment.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications, and instructs CEAs not to verify inclusion of potential devices in a registered entity's FRM as required by the original CAN-0018. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. This CAN will remain in effect until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable.

CEAs are instructed to assess compliance by:

1. CEAs are instructed to look at the entity's current FRM[3] to verify the elements of terminal equipment. CEAs are not to look further back in time to determine non-compliance or a Possible Violation because prior versions of an entity's FRM did not include, at a minimum, all of the terminal equipment identified in this CAN.
2. CEAs are to review the entity's current and prior FRMs to determine whether the entity's current FRM identifies a new most limiting Equipment Rating. If the entity listed a new most limiting Equipment Rating that should have been previously identified, the CEA is instructed to find non-compliance or a Possible Violation.

[2] A CEA may consider a current transformer that is part of a Protection System as an element to be accounted for under relay protective devices, terminal equipment, or both categories depending upon the entity's rating methodology. However, an entity's rating methodology must address all current transformers that could limit the Equipment Rating.

[3] "Current" means the Facility Ratings methodology in effect at the time of the audit. This is consistent with compliance monitoring guidance provided in the 2012 CMEP Implementation Plan and AML.

For any enforcement action in process and for audits that have been initiated,[4] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

CEAs are to look for evidence that the registered entity's current FRM addresses the equipment specified by R1.2.1, including terminal equipment as defined above.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
June 17, 2011	Posted Final CAN	
November 11, 2011	Posted Revised CAN	Removed "Potential Devices;" added "Current Transformers" and modified Fuses by adding "primary." Added additional effective date information.

[4] "Initiated" means that a registered entity has received notification of the upcoming audit.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Compliance Application Notice — 0018

~~Compliance Application:~~ FAC-008 R1.2.1 Terminal Equipment

Posted June 17, 2011
Reposted November 11, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entities
Transmission Owner~~s~~ (TO)
Generator Owner~~s~~ (GO)

Issue: What equipment is included under the term "~~Terminal~~ terminal ~~Equipment~~equipment" in the NERC Reliability Standard FAC-008?
For the purpose of aiding a CEA, this CAN provides instruction for assessing ~~NERC received a request for clarification of~~ what equipment ~~is included in the term~~should be considered "terminal equipment" ~~in~~ under FAC-008 ~~Requirement (R) 1.2.1~~.

~~**Reliability Objective**~~
~~The reliability objective is to foster compliance with the NERC Reliability Standards through clear communication of the meaning of terms used in a standard.~~

Background
Standard FAC-008 does not outline what equipment is classified as~~Registered Entities were unclear as to what equipment was subject to the standard under the term~~ "terminal equipment~~.~~" under R1.2.1.

Compliance Application
FAC-008 provides, in pertinent part:

> ***R1.2.1.*** *The scope of equipment addressed shall include, but not be limited to, generators, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.*

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards or requirements.

Formatted: Font: 11 pt
Formatted: Font: 11 pt
Formatted: Indent: Left: -0.5", Don't adjust space between Latin and Asian text
Formatted: Font: 11 pt
Formatted: Not Superscript/ Subscript
Formatted: Indent: Left: -0.5"

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

For the purpose of documenting the methodology used for developing Facility Ratings under FAC-008, the focus is on series-connected equipment that could have the most limiting applicable Equipment Rating.

CEAs are instructed to verify that a registered entity has included the following equipment as "terminal equipment" under FAC-008 R1.2.1:

~~The term "terminal equipment" includes:~~

- Wave traps
- Current transformers[2]
- ~~Potential devices~~
- Disconnect switches
- Breakers
- Primary Fuses
- Any piece of series-connected equipment that compromises a Facility ~~is in series with the circuit~~ and that could have the most ~~become a~~ limiting ~~element~~applicable Equipment Rating~~.~~

In the event an entity does not include a rating methodology for one or more of the above listed equipment types, a CEA is to verify that the entity does not own such equipment.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications, and instructs CEAs not to verify inclusion of potential devices in a registered entity's FRM as required by the original CAN-0018. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. This CAN will remain in effect until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable.

~~is effective for FAC-008 upon posting on the NERC Web site. It supersedes all prior communications and will remain in effect until a future CAN supersedes it or until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable, or until it is superseded by a future CAN that addresses this particular Standard and Requirement.~~

CEAs are instructed to assess compliance by:

1. CEAs are instructed to look at the entity's current FRM[3] to verify the elements of terminal equipment. CEAs are not to look further back in time to determine non-compliance or a Possible Violation because prior versions of an entity's FRM did not include, at a minimum, all of the terminal equipment identified in this CAN.
2. CEAs are to review the entity's current and prior FRMs to determine whether the entity's current FRM identifies a new most limiting Equipment Rating. If the entity listed

[2] A CEA may consider a current transformer that is part of a Protection System as an element to be accounted for under relay protective devices, terminal equipment, or both categories depending upon the entity's rating methodology. However, an entity's rating methodology must address all current transformers that could limit the Equipment Rating.

[3] "Current" means the Facility Ratings methodology in effect at the time of the audit. This is consistent with compliance monitoring guidance provided in the 2012 CMEP Implementation Plan and AML.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Font: 11 pt
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Font: 11 pt
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Font: 11 pt
Formatted: Font: 11 pt
Formatted: Indent: Left: -0.25", Don't adjust space between Latin and Asian text
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Not Superscript/ Subscript
Formatted: Not Superscript/ Subscript
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Not Superscript/ Subscript
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Indent: Left: -0.5"
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Indent: Left: 0.25", Numbered + Level: 1 + Numbering Style: 1, 2, 3, … + Start at: 1 + Alignment: Left + Aligned at: 0.75" + Indent at: 1", Don't adjust space between Latin and Asian text
Formatted: Font: 11 pt
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Not Superscript/ Subscript
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Indent: Left: 0.25"
Formatted: Not Superscript/ Subscript
Formatted: Centered

a new most limiting Equipment Rating that should have been previously identified, the CEA is instructed to find non-compliance or a Possible Violation.

For any enforcement action in process and for audits that have been initiated,[4] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

~~Providing~~ Evidence of Compliance

CEAs are to look for evidence that the registered entity's current FRM addresses the equipment specified by R1.2.1, including terminal equipment as defined above.

~~To demonstrate compliance with sub-requirement R1.2.1, a registered entity's Facility Ratings Methodology must address the equipment specified by R1.2.1, including terminal equipment as defined above.~~

For more information please contact:

Michael Moon
Director of Compliance Operations

Michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of ~~Compliance Standards~~ Interface and Outreach
Valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
June 17, 2011	Posted Final CAN	
November 10, 2011	Posted Revised CAN	Removed "Potential Devices;" added "Current Transformers" and modified Fuses by adding "primary." Added additional effective date information.

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.*~~

[4] "Initiated" means that a registered entity has received notification of the upcoming audit.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Not Superscript/ Subscript
Formatted: Font: 11 pt
Formatted: Indent: Left: 0.5", No bullets or numbering
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Font: 11 pt
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Indent: Left: -0.5", Don't adjust space between Latin and Asian text
Formatted: Font: 11 pt
Formatted: Indent: Left: -0.5"
Formatted: Not Superscript/ Subscript
Formatted: Font: 11 pt, Not Superscript/ Subscript
Formatted: Indent: Left: -0.5"
Formatted: Font: 11 pt
Formatted: Indent: Left: -0.5"
Formatted: Indent: Left: -0.5"
Formatted Table
Formatted: Centered

Industry Comments for CAN-0018

Comment Topics	Main Points	Industry Suggestions
Bullets 1 and 3 in the Effective Period for a CAN section contradict one another	Bullet 1 states that CEAs should not allege a Possible Violation because prior versions of an entity's Facility Ratings Methodology (FRM) did not include all terminal equipment. No conditions are placed on bullet 1. Bullet 3 indicates that a Possible Violation should be allegedif the terminal equipment is the limit with the updated FRM and the prior FRM did not include the terminal equipment.	Reform bullets
CAN inappropriately expands the scope	This CAN continues to have language that expands the scope of the Standard. Simply providing a list that was not included in the approved standard introduces additional requirements that were not developed or approved through the standards development process	Revise CAN and reevaluate the bullets
Can should be modified for defining the term "terminal equipment".	The language "not limited to" does not allow the CAN to develop a list of additional equipment to be considered under FAC-008. By the ROP, this is a modification to the standard and legally must be balloted to be effective.	Standard FAC-008 clearly provides a list to define the scope of equipment to include, this list of terminal equipment, if appropriate, needs to be included in the standard if agreed to by the industry. It should not be put forth in a CAN, as a compliance point, without full industry review and agreement through the standards development process.
Effective Period for CAN section issue	The first and second paragraph under the effective Period for Can section should be deleted	The first and second paragraph under the effective Period for Can section should be deleted

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0008 Comment Analysis Summary

PRC-005 R2 Basis for First Maintenance and Testing Date

CAN-0008 was originally posted as a final CAN on April 19, 2011. The original CAN provided instruction for assessing whether an entity was following its Protection System maintenance and testing program as of the mandatory date of June 18, 2007. The CAN has been revised to incorporate the direction provided by the NERC Board of Trustees in August of 2011 and has been reposted as final on November 16, 2011.

The revised CAN was posted for industry comment on the NERC web site on September 1, 2011, and the comment period expired on September 21, 2011. NERC received 24 comments from various industry stakeholders and trade associations, which are identified by name below. The main themes of the comments consisted of the following four categories: errata changes, the scope and legal basis, and the effective date of the CAN. As discussed below, the main area of concern with the revised CAN was that CEAs are instructed to verify the last date equipment was maintained and tested, regardless if that date was prior to the mandatory and effective date.

Errata

The recommended errata changes were implemented in order to correct the second bullet of the first example in the CAN. For clarity, the CAN now reads “on or after November 2003.” NERC staff thanks the commenters for pointing out this recommended change in the CAN.

Scope and Legal Basis

There were several recommended substantive changes to the CAN in regard to scope and the validity of the practice of verifying evidence prior to June 18, 2007. The commenters further stated that NERC has no legal basis for requiring entities to produce documents related to any maintenance or testing performed prior to June 18, 2007. The suggestion from industry was to have June 18, 2007 be considered as the start time for any interval associated with PRC-005.

As explained in a number of different forums, when CEAs request evidence of an entity’s last maintenance and testing date that occurred prior to the mandatory effective date of June 18, 2007, this evidence is used to demonstrate compliance with both PRC-005 R2.1 and R2.2 beginning on June 18, 2007. There is no inquiry regarding compliance prior to June 18, 2007. In addition, CEAs are instructed to accept evidence other than maintenance and testing records because NERC understands that those may not have been kept with the same consistency prior to June 18, 2007. As examples, some registered entities kept records of substation inspections that did not specify all of the maintenance and testing conducted during each visit but coupled with other documents, including

company procedures and attestations, demonstrated that the company in fact maintained and tested devices in connection with such inspections.

In regard to R2.1, the entity's last maintenance and testing date provides evidence of a starting point for the entity's interval to ensure that maintenance and testing is currently being performed within the schedule established in the registered entity's own program. PRC-005 R2.1 provides that an entity's documentation of its program's implementation shall include:

Evidence Protection System devices were maintained and tested within the defined intervals.

A CEA is thus required to verify that a registered entity, as of June 18, 2007, was maintaining and testing its Protection System devices according to the intervals the entity determined. Without knowing the last test date, it would be impossible for a CEA to determine if a registered entity was within its interval for maintenance and testing. It would also be impossible for a CEA to be able to determine the basis for the entity's first maintenance and testing date after June 18, 2007.

Further, PRC-005 R2.2 provides that an entity's documentation of its program's implementation shall include:

Date each Protection System device was last tested/maintained.

This requirement is explicit and was provided without regard to whether that date was before or after June 18, 2007. Further, the plain language of PRC-005 Requirement 2 does not foreclose the option to verify evidence prior to June 18, 2007. There is no language in the standard that defines or establishes timelines.

However, as indicated, different types of evidence can be used to identify testing and maintenance dates that occurred prior to June 18, 2007.
The legal basis to request evidence to demonstrate compliance with the requirements is provided in the NERC Rules of Procedure, Appendix 4C, Sections 3.1.1 and specifically 3.1.4.2, which was clarified in the version effective January 1, 2011. In relation to this issue, this section provides that a registered entity should be able to demonstrate compliance from June 18, 2007 through the audit period. The specific language of Section 3.1.4.2 states:

> The Registered Entity's data and information should show compliance with the Reliability Standards that are the subject of the Compliance Audit for the period beginning with the day after the prior audit by the Compliance Enforcement Authority ended (or the later of June 18, 2007 or the Registered Entity's date of registration if the Registered Entity has not previously been subject to a Compliance Audit), and ending with the End Date for the Compliance Audit.

Section 3.1.1, Compliance Audit Process Steps, states:

> The Registered Entity provides to the Compliance Enforcement Authority the required information in the format specified in the request.

Therefore, the CAN maintains the instruction for CEAs to verify evidence that establishes a registered entity's last Protection System maintenance and testing date and intervals, regardless if the evidence required to demonstrate compliance is dated prior to June 18, 2007. These requirements were known to industry from April 1, 2005, the effective date of the standard, over 2 years prior to the mandatory and effective date of June 18, 2007, and were visible as registered entities were developing their Protection System Maintenance and Testing programs.

The CAN has attempted to clarify that there is some flexibility in regards to what evidence may be acceptable, including an attestation along with other corroborating evidence. NERC understands the concerns of industry and wants to emphasize that the rationale for this CAN is to ensure consistency of application throughout the ERO and to assist industry in understanding the expectations of the CEAs s

Effective Date

Several commenters believe that NERC should incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted by NERC as final and provides in that posting an implementation and effective date which cannot be earlier than the posted date. There has been confusion, according to industry, about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

The effective date of CAN-0008 is April 19, 2011, which is the effective date of the original CAN posting. Because the revisions to this CAN did not materially alter the compliance application contained in the previously posted version, there is no need to establish a new effective date.

Conclusion

The analysis spreadsheet for CAN-0008 is posted on the NERC website. Because the spreadsheet format may not provide sufficient visibility into the effort that NERC puts into reviewing all of the comments received with respect to this CAN, this document is intended to supplement that information. Feedback from all sources is key and NERC staff thanks industry for the time and effort put into providing that feedback. If you would like further discussion on CAN-0008, please contact us at cancomments@nerc.net.

Industry Representatives that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
Associated Electric Cooperative, Basin Electric Power Cooperative, and Tri-State Generation and Transmission Association
Austin Energy
Bonneville Power Administration (BPA)
Central Lincoln
Constellation Energy (CEG)
Dominion Resources Services, Inc.
Farmington Electric Utility
Florida Municipal Power Authority (FMPA)
Fort Pierce Utilities Authority (FPUA)
Indeck Energy Services
Ingleside Cogeneration
Kansas City Power & Light (KCP&L)
Lakeland Electric
Liberty Electric
Manitoba Hydro
MidAmerican Energy Company
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
Progress Energy (PGN)
PSEG
Westar Energy
Western Farmers Electric Cooperative

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
National Rural Electric Cooperative Association (NRECA)

Industry Comments for CAN-0008

Comment Topics	Main Points	Industry Suggestions
Scope	Prior to June 18, 2007, entities had no mandatory testing/maintenance requirements and were not required to preserve evidence of testing/maintenance completed. NERC has no legal basis for requiring entities to produce documents related to any maintenance or testing performed prior to June 18, 2007. That date should be considered the start time for any periodic cycle associated with PRC-005. Not only is there no demonstrable reliability benefit from requiring this data, reliability problems may arise as a consequence of this requirement. The use of regional and NERC resources on this matter will mean less available resources for enhancing reliability in other, more pressing areas.	Prohibit the CAN from requiring evidence prior to June 18, 2007.
Errata	There is a minor error in Example 1 bullet 2 should be November 2003 or later.	Make changes for clarity.
Effective Dates	The effective date of this CAN should be date it is posted as final, not the posted date (April 19, 2011) of the previous final version of CAN-0008	Change effective date of CAN to time CAN is posted as final
Evidence	CAN-0008 requires evidence retention from a period of time when evidence was not required and may not exist. Nowhere in the standard do the requirements stipulate that the testing had to be completed prior to June 18, 2007.	The revised draft CAN-0008 should be further modified to clarify the amount and type of evidence required to demonstrate compliance with PRC-005-1 R2.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0008

PRC-005-1 R2 Basis for First Maintenance and Testing Date
Posted: April 19, 2011
Revised: November 11, 2011

Primary Interest Groups

Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Transmission Owner (TO)
Generation Owner (GO)
Distribution Provider (DP) that owns a transmission Protection System

Issue: Under what circumstances are CEAs required to consider evidence dated before June 18, 2007 in connection with their review of issues related to PRC-005-1 R2?

For the purpose of aiding a CEA, this CAN provides instruction for assessing whether an entity was following its Protection System[2] maintenance and testing program starting from June 18, 2007.

Compliance Application

CEAs are to obtain the last date a registered entity tested and maintained its Protection System devices in order to verify compliance with PRC-005-1 R2. Compliance with PRC-005-1 R2 is to be verified starting from June 18, 2007.

PRC-005-1 R2 provides, in pertinent part:

> ***R2.*** *Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization[3] on request (within 30 calendar days). The documentation of the program implementation shall include:*
>
> > ***R2.1.*** *Evidence Protection System devices were maintained and tested within the defined intervals.*
> >
> > ***R2.2.*** *Date each Protection System device was last tested/maintained.*

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards and requirements.
[2] The *NERC Glossary of Terms Used in Reliability Standards* defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."
[3] For this standard, the Regional Reliability Organization refers to the Regional Entity.

The last maintenance or test date is necessary for a CEA to determine whether a registered entity is conducting maintenance and testing within the intervals defined by its own Protection System maintenance and testing program, including in circumstances when the interval began prior to June 18, 2007, the mandatory and enforceable date of the standard.

A CEA is to verify that the registered entity included the date each Protection System device was last tested and maintained in its documentation of the registered entity's program implementation, and a CEA is to validate these documented dates.

To the extent that prior maintenance/test dates for specific devices occurred prior to June 18, 2007, the CEA is instructed to request evidence of such maintenance/testing because:

1) the evidence documents the last date the registered entity performed maintenance and testing if that occurred prior to June 18, 2007,
2) the evidence demonstrates that the registered entity was following its program starting from June 18, 2007, and
3) the evidence provides the basis for the registered entity's first post-June 18, 2007 maintenance and testing date.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[4] a CEA is to apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

A CEA is to obtain corroborating evidence regarding the pre-June 18, 2007 maintenance and testing date from the registered entity including, but not limited to:

- invoices
- maintenance reports
- emails
- orders for parts

[4] "Initiated" means that a registered entity has received notification of the upcoming audit.

- hand-written notes
- an attestation with corroborating evidence

Additionally, CEAs are to verify evidence of when the last conducted maintenance and testing was performed on a registered entity's equipment over the entire audit period. Some examples are as follows:

Example 1
In this example, the registered entity has its first audit on April 10, 2010; it has a documented maintenance and testing interval of six years, and it conducted maintenance and testing on its equipment in November 2009. CEAs are to verify:

1) evidence of the registered entity's maintenance and testing activities in November 2009 (demonstrating compliance beginning in November 2009), and
2) evidence or records sufficient to demonstrate that the registered entity's prior maintenance and testing activity occurred in or after November 2003 (to show compliance between June 18, 2007 and November 2009).

Example 2
In this example, the registered entity has its first audit on April 10, 2010. It has a documented maintenance and testing interval of six years, it is due to conduct maintenance and testing in November 2012, and it has not conducted maintenance and testing on its equipment since the June 18, 2007 mandatory and enforceable date for the standard.

1) The CEA is to obtain evidence of the registered entity's maintenance and testing activities in November 2006 (demonstrating compliance beginning on June 18, 2007).
2) In this situation the CEA would not require evidence of the registered entity's November 2000 maintenance and testing.
3) During the next audit, the CEA would require evidence of the registered entity's November 2012 maintenance and testing.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
April 19, 2011	Posted Final CAN	
November 11, 2011	Posted Revised CAN	Revised target audience to CEAs

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0008

~~Compliance Application:~~ PRC-005~~-1~~ R2 ~~Pre June 18, 2007 Evidence~~Basis for First Maintenance and Testing Date

Posted: April 19, 2011
Revised: Month XX, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity~~ies~~
Transmission Owner~~s~~ (TO)
Generation Owner~~s~~ (GO)
Distribution Provider~~s~~ (DP) that owns a transmission Protection System

Issue: Under what circumstances are CEAs required to consider evidence dated before June 18, 2007 in connection with their review of issues related to PRC-005-1 R2?
~~Requirement for Registered Entities to maintain pre-June 2007 evidence~~
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether an entity was following its Protection System[2] ~~NERC Compliance received a request for clarification on PRC-005-1 R2 regarding the requirement for pre-June 18, 2007 evidence to determine compliance with an entity's~~ maintenance and testing program starting from June 18, 2007.
~~Specifically, what is the validity of a Regional Auditor to ask for evidence pre-June 2007 even though there was no obligation to retain records until at least June 18, 2007?~~

~~**Reliability Objective**~~
~~To ensure that maintenance and testing of Protection Systems are being conducted within defined intervals.~~

Compliance Application
~~Registered entities must be able to provide evidence to the Compliance Enforcement Authority~~CEAs are to obtain the last date a registered entity tested and maintained ~~to substantiate the last date it tested and~~

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards and requirements.
[2] The *NERC Glossary of Terms Used in Reliability Standards* defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."

~~maintained~~ its Protection System[3] devices in order to verify~~demonstrate its~~ compliance with PRC-005-1 R2. Compliance with PRC-005-1 R2 is to be verified starting from June 18, 2007.

PRC-005-1 R2 provides, in pertinent part:

> ***R2.*** *Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization[4] on request (within 30 calendar days). The documentation of the program implementation shall include:*
>
> > ***R2.1.*** *Evidence Protection System devices were maintained and tested within the defined intervals.*
> >
> > ***R2.2.*** *Date each Protection System device was last tested/maintained.*

~~*implementation of that program to its Regional Reliability Organization[5] on request (within 30 calendar days). The documentation of the program implementation shall include:*~~

~~***R2.1.*** *Evidence Protection System devices were maintained and tested within the defined intervals.*~~

~~***R2.2.*** *Date each Protection System device was last tested/maintained.*~~

The last maintenance or test date is necessary for a CEA ~~In order~~ to determine whether a registered entity is conducting maintenance and testing within the intervals defined by its own Protection System maintenance and testing program, including in circumstances when ~~regardless if~~ the interval began prior to June 18, 2007, ~~bridged~~ the mandatory and enforceable date of the standard. ~~the compliance enforcement authority must have a substantiated last maintenance or test date.~~

~~Therefore~~A CEA is to verify that the registered entity included the date each Protection System device was last tested and maintained in its documentation of the registered entity's program implementation; ~~The registered entity's last date for maintenance and testing must be included in the documentation of its program's implementation as required by the Standard,~~ and a CEA is to validate these documented dates.

To the extent that prior maintenance/test dates for specific devices occurred prior to June 18, 2007, the CEA is instructed to request evidence of such maintenance/testing because: ~~Any required pre-June 18, 2007 evidence serves three purposes:~~

1) ~~it~~the evidence documents the last date the registered entity performed maintenance and testing if that occurred prior to June 18, 2007,
2) the evidence ~~it~~ demonstrates that the registered entity was following its program starting from June 18, 2007, and

---

[3] ~~The *NERC Glossary of Terms Used in Reliability Standards* defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."~~

[4] For this standard, the Regional Reliability Organization refers to the Regional Entity.

[5] ~~For this standard, the Regional Reliability Organization refers to the Regional Entity.~~

3) the evidence it provides the basis for the registered entity's first post-June 18, 2007 determination of its next maintenance and testing date.

The auditor must be able to validate these documented dates. It is acceptable for the documented dates to be evidenced by whatever records the registered entity has in regards to the maintenance and testing – including, but not limited to: invoices, maintenance reports, confirming emails, orders for parts, hand-written notes, and/or an employee's signed attestation of the testing supported by corroborating evidence.

Any required pre-June 18, 2007 evidence serves two purposes: it documents the last date the registered entity performed maintenance and testing, if that occurred prior to June 18, 2007, and it also provides the basis for the registered entity's post-June 18, 2007 determination of its next maintenance and testing date.

Compliance GuidanceEvidence of Compliance

A CEA is to obtain corroborating evidence regarding the pre-June 18, 2007 maintenance and testing date from the registered entity including, but not limited to:

- invoices
- maintenance reports
- emails
- orders for parts
- hand-written notes
- an attestation with corroborating evidence

Additionally, The registered entity will be required to provideCEAs are to verify evidence of when it the last conducted maintenance and testing was performed on its a registered entity's equipment over the entire audit period. Some examples are as follows:

Example #1

In this example, the registered entity has its first audit on April 10, 2010; it has a documented maintenance and testing interval of 6six years,; and it conducted maintenance and testing on its equipment in November 2009. The auditor or Compliance Enforcement AuthorityCEAs are to verify would require:

1) evidenceevidence of the registered entity'ies maintenance and testing activities in November 2009 (demonstrating compliance beginning in November 2009), and
2) some evidence or records sufficient to demonstrateing that of the registered entity's prior maintenance and testing activity occurred in or after November 2003 or sooner (to show compliance from between June 18, 2007 through and November 2009).

Example #2

In this example, the registered entity has its first audit on April 10, 2010;. Iit has a documented maintenance and testing interval of 6 six years;, it is due to conduct maintenance and testing in November 2012, and it has not conducted maintenance and testing on its equipment since the June 18,

2007 mandatory and enforceable date for the standard. ~~The auditor~~ CEA ~~or Compliance Enforcement Authority would require:~~

1) The CEA is to obtain evidence of the registered ~~entities~~ entity's maintenance and testing activities in November 2006 (demonstrating compliance beginning on June 18, 2007).
2) In this situation the ~~auditor or Compliance Enforcement Authority~~CEA would not require evidence of the registered entity's November 2000 maintenance and testing.
3) During the next audit, the ~~auditor or Compliance Enforcement Authority~~CEA would require evidence of the registered entity's November 2012 maintenance and testing.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[6] a CEA is to apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

~~**Prior Communications**~~

~~*RSAW January 13, 2010 – Transmission & Generation Protection System Maintenance and Testing~~
~~*NERC Relay Maintenance Technical Reference *Protection System Maintenance – A Technical Reference* Section 8.2, dated September 13, 2007~~
~~*Order 693, ¶ 1474, issued March 16, 2007~~
~~*Code of Federal Regulations, Title 18 Subchapter B Part 39.2(d)~~
~~*NERC Rules of Procedure, Section 401.3~~
~~*NERC Compliance Monitoring and Enforcement Program (CMEP), effective 1/11/2011, Sections 3.1.4.2 and 9.1~~

For more information please contact:

Michael Moon
Director of Compliance Operations

Valerie Agnew
Manager of Interface and Outreach

[6] "Initiated" means that a registered entity has received notification of the upcoming audit.

michael.moon@nerc.net
404-446-2567

valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
April 19, 2011	Posted Final CAN	
November 16, 2011	Posted Revised CAN	Revised target audience to CEA

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0010 Comment Analysis Summary

Implementation of Annual in Reliability Standards Requirements

CAN-0010 was originally posted as a final CAN on April 19, 2011. The original CAN provided instruction for assessing whether an entity was performing tasks within a calendar year when "annual" was listed in a standard without a clear instruction for the applicable timeframe. The CAN has been revised to incorporate the direction provided by the NERC Board of Trustees in August of 2011 and was reposted as final on November 16, 2011.

The revised draft CAN was posted for industry comment on the NERC web site on October 10, 2011, and the comment period expired on October 31, 2011. NERC received comments from 13 registered entities and 5 trade associations, which are identified below. The main themes of the comments consisted of the following four categories: background section, scope, effective date and evidence of compliance.

Background

Industry members stated that there has been no analysis performed that would indicate that different implementations for annual activities has had an impact on reliability, and that the Background section may provide some information that is incorrect and misleading.

In response to the comments, registered entities were using their own implementation of annual and were not always performing the required task "annually." There were instances where registered entities provided "grace periods" for conducting their annual requirements and, due to the grace periods, were not conducting annual activities at least once every calendar year.

There are two possible definitions for "Calendar Year": 1) once every rolling 12 months or 2) once every defined calendar year. In order to maintain consistency across the ERO, meet the requirement of the standard and at the same time provide flexibility to registered entities, this CAN was drafted to instruct Compliance Enforcement Authority (CEA) staff to verify that, when not otherwise specified in the standard, annual activities were conducted at least once every calendar year.

Scope

There were several recommended substantive changes to the CAN in regard to scope. The commenters stated that CAN-0010 goes beyond the requirements in the standards and that Compliance Enforcement Authority (CEA) staff should not be instructed to verify evidence of annual implementation when a standard is silent to the matter.

In response to the comments, CAN-0010 was drafted to provide flexibility but to also ensure that activities were performed at least once per calendar year. Many commenters were in favor of the third bullet in the Compliance Application section of the CAN, as it provides flexibility for registered entities' internal compliance program; others stated this was confusing and just a restatement of the first bullet. It was determined to keep the third bullet in favor of providing suggestions for flexibility.

There were also several comments from industry stakeholders and trade associations that recommended the language referencing an entity's culture of compliance should be stricken from the CAN as this was unnecessary for the compliance application. In response, the "culture of compliance" language was removed.

Another sentence recommended to be removed was in regard to the "best practice" of performing the activity with no more than 15 months between the events required by the standard. This "best practice" had been added to provide a framework of what would be considered good practices; certainly a true "best practice" for an annual requirement would be to perform the activity once every rolling 12 months. The term "best practice" was used to indicate this was not an enforceable suggestion. This language remained in the CAN as a suggestion for industry to conduct annual activities no more than 15 months apart.

To recap, the compliance application states that a CEA will verify that a registered entity conducted required annual activities at least once in a calendar year (Jan 1 - Dec 31), unless otherwise provided in the standard or requirement. Several commenters stated that this practice could reward an entity that waited 23 months between activities, while an entity that performs the same task within 13 months but not in a calendar year would be found in noncompliance. This was a concern for reliability that an entity may wait 23 months between activities. However, if the entity did perform a task within 23 months after the last activity (January in year one and December of following year), the entity would be forced to complete their activity within 12 months of the third year (December of year three) to remain within the bounds of "once every calendar year." While this is not a best practice, the "once every calendar year" compliance application and practical operation would not permit this practice to prevail over time, and it is anticipated that entities with strong cultures of compliance would not allow this to happen at all, absent unusual circumstances.

Effective Date

Several commenters believe that NERC should incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted by NERC as final and provides in that posting an implementation and effective date, which cannot be earlier than the posted date. There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

To clarify the effective date in CAN-0010, which is April 19, 2011, the effective date remains the same date as the original posting. Because the change to the CAN did not materially revise the compliance application in the previously posted version, it is a continuation of the original compliance application, and therefore this CAN was dated the same date of the earlier version.

Evidence of Compliance

Several commenters stated that the CAN requires evidence beyond the intent of the standards as written. There is concern that this standard is in fact imposing more stringent criteria on entities beyond the intent of the standard as written. This allows a CEA to enforce more stringent criteria on individuals who may have proposed a best practice approach, resulting in an increased exposure to noncompliance.

Other commenters stated that parts of the Evidence of Compliance section seem to be in conflict. Paragraph A guides CEAs not to take compliance actions if an entity has a best practice of performing something annually not to exceed 15 months, but in fact may perform the function between 15 months and 24 months, or annually. While if an entity has implemented a rolling 12-month process, it could be exposed if the 12 months are exceeded for any reason.

The CAN was drafted to encourage registered entities to take a more stringent approach to conducting annual activities and instructs CEAs not to determine non-compliance or a Possible Violation as long as the registered entity has conducted the annual activity at least once in every Calendar Year, even if the registered entity did not meet its own requirement for the implementation of annual activities.

Conclusion

The analysis spreadsheet for CAN-0010 is posted on the NERC website. NERC received feedback that the spreadsheet format did not provide industry visibility into the effort that is put into reviewing all of the comments. In order to provide increased transparency to the comment analysis phase of the CAN process, this document has been created to supplement the information contained in the spreadsheet. NERC staff thanks industry members for the time and effort put into providing the comments and feedback for CAN-0010. If you would like further discussion on CAN-0010, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
Austin Energy
Bonneville Power Administration (BPA)
Constellation Energy (CEG)
Consumers Energy
Dominion Resources Services, Inc.

Farmington Electric Utility System (FEUS)
Ingleside Cogeneration/Occidental
LG&E and KU Services Company
MidAmerican Energy Company
Oncor Electric Delivery
Pepco Holdings, Inc.
Southern Company

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
ISO/RTO Council Standards Review Committee (IRC SRC)
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
National Rural Electric Cooperative Association (NRECA)
NPCC Entities (industry)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0010

Implementation of "Annual" in Reliability Standards Requirements

Posted: April 19, 2011
Revised: November 16, 2011

Primary Interest Groups

Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Registered Entities subject to reliability standards containing a requirement to repeat some performance on an annual basis (annual requirement)

Issue: How is a CEA to assess whether a registered entity met the "annual" requirement of a reliability standard?

This CAN provides instruction to CEAs on how to assess compliance when a standard requires an "annual" activity.

Background

The reliability standards contain numerous requirements for registered entities to perform an action "annually." Without clear guidance, registered entities determined their own implementation of the term "annual," which is contained in a multitude of standards, without certainty that the implementation of the requirements established compliance with the applicable reliability standards. The intent of most annual requirements is to ensure that entities perform a particular task on a regular basis, with an established maximum interval between the occasions when the task is performed. Intervals that are too long affect the ability of the activity to protect reliability.

Compliance Application

NERC has established clarity for the implementation of annual requirements as well as parameters for CEAs to assess compliance regarding the registered entity's implementation of an annual requirement. The registered entity's implementation of annual requirements may apply to standards that require an annual action or event, unless a standard contains a definition of annual. In cases where the standard contains a definition of the term "annual" or "annually," that definition remains and is applicable to that standard. In cases where the standard specifies how annual requirements are implemented, that language remains and is applicable to that standard. This CAN does not supersede or change any language contained in a standard.

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

In all standards where the term "annual" is not defined, CEAs are to determine if the registered entity established its own implementation of annual requirements within the parameters provided below. CEAs are instructed to look for a registered entity's documented implementation of annual requirements as the basis for determining compliance. CEAs are to verify whether a registered entity documented either one implementation of annual across all standards that do not specify how an annual requirement is implemented, or an implementation for each individual standard.

CEAs are to verify that a registered entity implemented annual requirements pursuant to the guidelines below:

a) Within a Calendar Year, beginning on January 1 and ending on December 31 (Calendar Year):

   In this option, CEAs are to verify that the activity or event is conducted at least once every Calendar Year. A best practice is that the activities or events should not be too far apart. For example, a registered entity's documentation may state that there should be no more than 15 months between the events required by the standard.

   Or:

b) Rolling 12 months: The activity or event is conducted at least once within the last 12-month period.

   Or:

c) CEAs are to verify whether registered entities have documented another implementation of annual[2] requirements along with procedures that define that implementation. However, CEAs are to verify that any alternative documented method demonstrates that the required activity was conducted at least once every Calendar Year.

   Regardless of the registered entity's documented implementation of annual, that implementation will not supersede any requirement stated in the standard.

This implementation of annual will be in effect throughout the ERO, will supersede any prior guidance, and is in effect until the term "annual" is defined in each standard.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain

[2] For example, a registered entity may define "annual" as "at least once within the last 12-month period" and may include a grace period of two months. In this situation, the activity or event is still to be conducted at least once every Calendar Year.

in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

CEAs are to assess compliance based on an entity's implementation of one of the below situations:

- A CEA is instructed not to find noncompliance or a possible violation if a registered entity is following its own documented implementation of annual[4] and its own documented implementation plan for annual requirements.
- A CEA is instructed to look for evidence that a registered entity has and adheres to its own documented implementation of annual and its own documented implementation plan for annual requirements. If an entity does not adhere to its implementation, a CEA is instructed to find noncompliance or a possible violation, *unless* the entity conducts the annual activity at least once every Calendar Year.
- If a registered entity does not have a documented implementation of annual and its own documented implementation plan for annual requirements, a CEA is to assess the entity's compliance based upon Option A contained above: that the activity or event is conducted at least once each Calendar Year.

A CEA is instructed not to find noncompliance or a possible violation if the activity or event is conducted at least once: (1) within each Calendar Year OR (2) within a documented rolling 12-month period.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.
[4] Provided that, as indicated above, the registered entity's definition of annual causes the activity or event to occur at least once every Calendar Year.

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
April 19, 2011	Posted Final CAN	
November 16, 2011	Posted Revised CAN	Revised target audience to CEAs

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Compliance Application Notice — 0010

~~Compliance Application: Definition of "Annual" and~~ Implementation of Annual Requirements

Posted: April 19, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional ~~Entities~~Entity
Registered Entities subject to Reliability Standards containing a requirement to repeat some performance on an annual basis (annual requirement)

Issue: How is a CEA to assess whether a registered entity met the ~~The definition of~~ "annual" requirement of a reliability standard? ~~and implementation of annual requirements~~
This CAN provides instruction to CEAs on how to assess compliance when a standard requires an "annual activity. ~~NERC received a request for clarification of the definition of the term "annual" and guidance regarding the implementation of annual requirements.~~

~~**Reliability Objective**~~
~~To maintain reliability through the consistent application of the annual requirements contained in NERC Reliability Standards. The intent of most annual requirements is to ensure that entities perform a particular task on a regular basis, with an established maximum interval between the occasions when the task is performed. Intervals that are too long degrade the value of the activity in protecting reliability.~~

Background
The reliability standards contain numerous requirements that Registered Entities perform an action "annually." Without clear guidance, registered entities determined their own ~~definition~~ implementation of the term "annual," which is contained in a multitude of standards, without certainty that the ~~its definition or~~ implementation of the requirements established compliance with the applicable Reliability Standards. The intent of most annual requirements is to ensure that entities perform a particular task on a regular basis, with an established maximum interval

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

Formatted: Font: (Default) +Body

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.~~
~~Princeton, NJ 08540~~
~~609.452.8060 | www.nerc.com~~

between the occasions when the task is performed. Intervals that are too long affect the ability of the activity to protect reliability.

Compliance Application

NERC has established clarity for the implementation of annual requirements ~~term "annual,"~~ as well as parameters for CEAs to assess compliance regarding the ~~implementation of a~~ registered entity's ~~definition~~ implementation of an annual requirement. The registered entity's implementation of annual requirements may ~~that will~~ apply to standards that require an annual action or event, unless a standard contains a definition of "annual." In cases where the standard contains a definition of the term "annual" or "annually," that definition remains and is applicable to that standard. In cases where the standard specifies how annual requirements are implemented, that language remains and is applicable to that standard. This CAN does not supersede or change any language contained in a standard.

In all standards where the term "annual" is not defined, CEAs are to determine if the registered entity ~~may determine~~ established its own implementation of ~~its definition of~~ annual requirements within the parameters provided below. CEAs are instructed to look for a~~, but must document its definition in order to provide that definition as the basis for its compliance. A~~ registered ~~entity~~ entity's ~~may~~ documented ~~one definition~~implementation of annual requirements as the basis for determining compliance. CEAs are to verify whether a registered entity documented either one implementation of annual across all standards that do not specify how an annual requirement is implemented, or documented an implementation ~~across all standards that do not specify how an annual requirement is implemented, or a registered entity may document a definition~~ for each individual standard.

CEAs are to verify that a ~~A~~ registered ~~entity may define "~~implemented annual~~" as:~~ requirements pursuant to the guidelines below:

a) ~~Annual – within~~Within a ~~calendar~~ Calendar ~~year~~Year, with the calendar year beginning on January 1 and ending on December 31 (Calendar Year).

   In this option, CEAs are to verify that the activity or event ~~must~~ is ~~be~~ conducted at least once ~~in~~ every Calendar Year. A best practice is that the activities or events should not be too far apart. For example, a registered entity's documentation may state that there should be no more than 15 months between the events required by the standard. ~~While including these parameters is not required, it is a best practice that demonstrates a concern for reliability.~~

b) Rolling 12 months – the activity or event ~~must have been~~is conducted at least once within the last 12-month period.

c) CEAs are to verify whether ~~R~~registered entities have ~~may have~~ documented another ~~definition~~ implementation of ~~"~~annual~~"~~[2] requirements along with ~~and~~

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Formatted: Font: 12 pt, Not Superscript/ Subscript

[2] For example, a registered entity may define "annual" as "at least once within the last 12-month period" and may include a grace period of two months. In this situation, the activity or event must still be conducted at least once in every Calendar Year.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com~~

procedures that define ~~its~~ their implementation of annual requirements. However, CEAs are to verify that ~~that differ from the options contained in this CAN;~~ any alternative documented method ~~must~~ demonstrates that the required activity was conducted at least once in every Calendar Year.

Regardless of the registered entity's documented ~~definition~~ implementation of annual, ~~it will not~~that implementation will not supersede any requirement stated in the standard.

This ~~definition~~ implementation of annual will be in effect throughout the ERO, will supersede any prior ~~definition~~ guidance, and is in effect until the term "annual" is defined in each standard.

Formatted: Font: 12 pt

Formatted: Font: 12 pt, Not Superscript/ Subscript

Formatted: Font: 12 pt

Formatted: Font: 12 pt, Not Superscript/ Subscript

Formatted: Font: 12 pt

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

CEAs are to assess compliance based on an entity's implementation of one of the below situations:

- A CEA is instructed not to find noncompliance or a possible violation if a registered entity is following its own documented implementation of annual[4] and its own documented implementation plan for annual requirements.
- A CEA is instructed to look for evidence that a registered entity has and adheres to its own documented implementation of annual and its own documented implementation plan for annual requirements. If an entity does not adhere to its implementation, a CEA is instructed to find noncompliance or a possible violation, *unless* the entity conducts the annual activity at least once every Calendar Year.

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.
[4] Provided that, as indicated above, the registered entity's definition of annual causes the activity or event to occur at least once every Calendar Year.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com~~

- If a registered entity does not have a documented implementation of annual and its own documented implementation plan for annual requirements, a CEA is to assess the entity's compliance based upon Option A contained above: that the activity or event is conducted at least once each Calendar Year.

A CEA is instructed not to find noncompliance or a possible violation if the activity or event is conducted at least once: (1) within each Calendar Year OR (2) within a documented rolling 12 month period.

~~**Compliance Guidance**~~

- ~~If a registered entity is following its own documented definition of annual[5] and its own documented implementation plan for annual requirements, a registered entity will be determined to be compliant in regard to the annual requirement of a standard.~~
- ~~If a registered entity has its own documented definition of annual and its own documented implementation plan for annual requirements but is not adhering to either, the registered entity will be found non-compliant with the annual requirement of the standard at issue, unless the entity is conducting the required activity or event at least once in every Calendar Year.~~
- ~~If a registered entity does not have a documented definition of annual and its own documented implementation plan for annual requirements, the entity's compliance will be determined based upon option (a) contained herein, which is that the activity or event must have been conducted at least once within each Calendar Year.~~

For more information please contact:

Michael Moon
Director of Compliance Operations

michael.moon@nerc.net
609-524-7028

Valerie Agnew
Manager of ~~Compliance Standards~~ Interface and Outreach
valerie.agnew@nerc.net
609-524-7075

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

[5] ~~The registered entity's definition of annual must provide for the activity or event to occur at least once in every Calendar Year.~~

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.~~
~~Princeton, NJ 08540~~
~~609.452.8060 | www.nerc.com~~

Posted Date	Action	Revision
April 19. 2011	Posted Final CAN	
Month XX, 2011	Posted Revised CAN	Revised target audience to CEA

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this compliance application notice is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com~~116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com~~

Industry Comments for CAN-0010

Comment Topics	Main Points	Industry Suggestions
Background Section	The Background provides some information that is incorrect and misleading.	There has been no analysis performed that would indicate that the use of annual has had an impact on reliability.
Scope	The “best practice” language should be removed. This allows a CEA to enforce a more stringent criteria on individuals who may have proposed a best practice approach, resulting in an increase exposure to non compliance.	Industry is suggesting to strike the best practice and culture of compliance language.
Effective Date	The effective period of the CAN should not be sooner than the final approval and final publishing of the CAN.	We recommend an implementation period of 12 months after approval.
Evidence of Compliance	CAN is requiring evidence beyond the intent of the standards as written. The Compliance Application section centers around the idea that an entity must have a definition of annual consistent with the CAN while the third bullet in the Evidence of Complianc	Remove third bullet in the Evidence of Compliance section.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0011 Comment Analysis Summary

PRC-005 R2 Interval Start Date for New Equipment

CAN-0011 was originally posted as a final CAN on April 19, 2011. The original CAN provided instruction for assessing the interval start dates and determining whether new Protection System equipment had been maintained and tested within the intervals defined in a registered entity's program. The CAN has been revised to incorporate the direction provided by the NERC Board of Trustees in August of 2011 and was reposted as final on November 16, 2011.

The revised draft CAN was posted for industry comment on the NERC web site on October 10, 2011, and the comment period expired on October 31, 2011. NERC received approximately 21 comments from registered entities and 3 comments from trade associations, which are identified below. The main themes of the comments consisted of the following four categories: errata changes, scope, effective date and evidence of compliance.

NERC received positive feedback from industry during the comment period, with commenters highlighting that CAN-0011 addresses a valid weakness in the language in PRC-005 R2. The industry feedback stated that it is not clear from the requirement when the first start date of a maintenance interval for newly deployed Protection System equipment should begin.

Errata

Several commenters recommended changing the issue statement. After reviewing all of the proposed language, the issue statement was reworded and has been clarified to better address the CAN topic of interval dates for new equipment.

There was a comment about the version of the standard not being listed (PRC-005-1 now reads PRC-005), which may cause confusion if a future standard is approved and becomes effective. This change was intentionally done for efficiency; the CAN would remain intact in the event that a new standard or interpretation was issued that did not address the issue in the CAN. As mentioned in the effective date section, if a revised standard or interpretation addresses the issue in a CAN, the CAN will be superseded and retired.

Scope

There were several recommended substantive changes to the CAN in regard to scope. Some of the comments claimed that CAN-0011 goes beyond the requirements in the standards and that Compliance Enforcement Authority (CEA) staff should not be instructed to verify evidence that may go beyond PRC-005 R2. Other comments stated that the CAN should be subject to NERC's formal standards development or interpretation process. Several commenters stated that the issue of pre-operational

testing is already being addressed through Standards Drafting Team (SDT) Project 2012-04 Protection System Commissioning Testing. Further, the SDT has issued a FAQ on the topic, and the CAN is in direct conflict with the guidance provided by the SDT, which states that the in-service date should be considered the start date for the entity's interval.

Several entities, including EEI, commented that new equipment testing is often conducted well in advance of placing the equipment in service. Although the pre-operational testing differs from maintenance and testing, completion of the pre-operational testing is the point at which a registered entity makes a determination of the condition of the equipment; additional tests are not conducted at the in-service date, which could be significant time after the pre-operational testing is done.

In response to the comments regarding the SDT, CAN-0011 was drafted to address the issues with compliance monitoring for the current effective standard, which does not have clear direction regarding interval start times for new equipment. Although there is a SDT working on the new version of PRC-005, that version has not been approved and is not in effect. While the FAQ document may provide rationale for the direction of the new version in the standard, it is not an enforceable document—only the current requirements of the in-force standard. NERC understands that this CAN may be superseded in the future with the issuance of the new standard, but CEA staff needs to consistently monitor compliance with the currently enforceable standards.

Another comment was in regard to whether CANs are considered the sole method for attaining compliance. It was pointed out that there are often multiple ways for an entity to comply with a standard, and in many cases requirements do not specifically define relevant terms or processes, thereby allowing a broad range of solutions, that an entity might achieve an equal level of compliance.

In response, the purpose of CANs is to create consistency, and therefore CEAs are expected to use the CAN to assess compliance. While there will be unique facts and circumstance that affect compliance assessment, that is to be the exception rather than the norm. The expectation is that the CAN should provide the range of activities that fulfill the requirement of the standard. If there is an equally effective means of achieving compliance, industry is welcome to present the information to NERC at cancomments@nerc.net.

Another scope concern received from industry was that CAN-0011 requires evidence of pre-operational testing to demonstrate compliance outside of a period in which the standards and/or this compliance application were effective. The comment stated that the CAN requires evidence before entities were aware that they even needed to collect or obtain such evidence for any compliance purpose. The commenter felt that CAN-0011 was an interpretation of the standard and should be vetted through the established stakeholder process.

In response to the comments, new Protection System devices are subject to a registered entity's current Protection System Maintenance and Testing Program. CAN-0011 instructs CEAs to verify that maintenance and testing are being conducted according to the intervals defined in the registered entity's program, which requires a start date for the interval.

Effective Date

Several commenters believe that NERC should incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted by NERC as final, and provides in that posting an implementation and effective date, which cannot be earlier than the posted date. There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

To clarify the effective date in CAN-0011, which is April 19, 2011, the effective date remains the same date as the original posting. Because the change to the CAN did not materially revise the compliance application in the previously posted version, it is a continuation of the original compliance application, and therefore this CAN was dated the same date of the earlier version.

Evidence of Compliance

Several commenters stated that there may be adequate forms of evidence other than pre-operation test reports. They went on to state that CANs are to verify compliance and show examples of at least one method to be compliant. CANs are not to specify the only way to be compliant.

In response, NERC has solicited industry to propose other methods of achieving compliance. Commenters stated that either 1) the in-service date should be the beginning of the interval or 2) there should not be an interval until the first maintenance and testing has been completed. The in-service date was determined to not be the appropriate date for the reasons discussed above. Delaying compliance monitoring until the first maintenance and testing date is not an option that supports reliability, and further, does not provide a basis for establishing the first maintenance and testing date.

Conclusion

The analysis spreadsheet for CAN-0011 has been posted on the NERC website. NERC received feedback that the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments. In order to provide increased transparency to the comment analysis phase of the CAN process, this document was created to supplement the information contained in the spreadsheet. NERC staff thanks industry members for the time and effort put into providing the comments and feedback for CAN-0011. If you would like further discussion on CAN-0011, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
Austin Energy
Bonneville Power Administration (BPA)
Buckeye Power
Constellation Energy (CEG)
Dominion Resources Services, Inc.
Duke Energy
Farmington Electric Utility System (FEUS)
Florida Municipal Power Agency (FMPA)
Great River Energy
Ingleside Cogeneration/Occidental
Kansas City Power and Light (KCP&L)
MidAmerican Energy Company
Old Dominion Electric Cooperative
Oncor Electric Delivery
PacifiCorp
Pepco Holdings, Inc.
Southwest Transmission Cooperative
Southern Company
Xcel Energy

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
National Rural Electric Cooperative Association (NRECA)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0011

PRC-005 R2 Interval Start Date for New Equipment

Posted: April 19, 2011
Revised: November 16, 2011

Primary Interest Groups

Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Transmission Owner (TO)
Generator Owner (GO)
Distribution Provider (DP) that owns a transmission Protection System

Issue: May pre-operational test[2] records be used as evidence to show that maintenance and testing was performed within the registered entity's defined maintenance and testing interval for new equipment?
For the purpose of aiding a CEA, this CAN provides instruction for assessing the interval start date for **new** Protection System equipment that affects the reliability of the Bulk Electric System (BES), for the purpose of determining whether new Protection System equipment had been maintained and tested within the intervals defined in a registered entity's program.

Compliance Application

In order to determine compliance with PRC-005 R2, CEAs are instructed to look for evidence that substantiates the last date a registered entity tested and maintained its Protection System[3] devices.

PRC-005 R2 provides, in pertinent part:

> ***R2.*** *Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization[4] on request (within 30 calendar days). The documentation of the program implementation shall include:*

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] Pre-operational testing may also be referred to as "commissioning tests." The "pre-operational test" means the last testing a registered entity conducts on the Protection System device before the device is put into service.
[3] The *NERC Glossary of Terms Used in Reliability Standards* defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."
[4] For this standard, the Regional Reliability Organization refers to the Regional Entity.

R2.1. *Evidence Protection System devices were maintained and tested within the defined intervals.*

R2.2. *Date each Protection System device was last tested/maintained.*

Without evidence demonstrating that new equipment was tested and was in appropriate condition to enter into service (the start date), a CEA cannot assess when the registered entity's maintenance or testing must occur.

As soon as the entity conducts its pre-operational testing, the interval begins for its maintenance and testing program.[5] The completion of the pre-operational testing, not the initiation of the pre-operational testing, is the point in time that the registered entity is aware of the operating condition of the equipment. Thus the completion date of the pre-operational testing is the date that should be used as the start date for the equipment's maintenance and testing interval. As pre-operational testing may occur over a period of time, the CEA is to verify the date that the pre-operational testing was completed for the equipment at issue.

The next maintenance and testing date to be verified by the CEA would be at some specific period of time after the start date, as defined by the interval defined in the registered entity's maintenance and testing program.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[6] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

To determine evidence of the start date for a registered entity's equipment's maintenance and testing interval, a CEA is instructed to look for the date the registered entity completed its equipment's pre-

[5] The registered entity's Protection System maintenance and testing program is only applicable for Protection System devices in service; however the date the equipment was placed in-service is not the date that should be used for the starting point of the maintenance and testing interval, unless the equipment was placed into service on the same date the pre-operational testing was completed.

[6] "Initiated" means that a registered entity has received notification of the upcoming audit.

operational testing that demonstrated that the equipment was deemed operational and ready to be placed into service.

In the event that a registered entity has equipment that changes status, such that it becomes subject to the standard (such as a radial line becoming a non-radial line), a CEA is instructed to look for either:

1. the date existing Protection System devices were last maintained or tested, or
2. the date the registered entity completed its equipment's pre-operational testing that demonstrated that the equipment was deemed operational and ready to be placed into service

as the start date for determining the equipment's maintenance and testing interval under the registered entity's maintenance and testing program.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
April 19, 2011	**Posted Final CAN**	
November 16, 2011	**Posted Revised CAN**	**Revised target audience to CEAs**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0011

~~Compliance Application:~~ PRC-005-1 R2 ~~New Equipment~~Interval Start Date for New Equipment

Posted: April 19, 2011
Revised: November 16, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional ~~Entities~~Entity
Transmission Owner (TO)~~s~~
Generator Owner (GO)~~s~~
Distribution Provider (DP)~~s~~ that own a transmission Protection System

Issue: May pre-operational test[2] records be used as evidence to show that ~~Evidentiary requirements for initial~~ maintenance and testing was performed within the registered entity's defined maintenance and testing interval for new equipment? ~~of new equipment in a Protection System~~
For the purpose of aiding a CEA, this CAN provides instruction for assessing the interval start date for **new** Protection System equipment affecting the reliability of the Bulk Electric System (BES) for the purpose of determining ~~Registered entities have requested that NERC provide clarification on~~ whether new Protection System equipment had been maintained and tested within the intervals defined in the ~~NERC Reliability Standard PRC-005 requires evidence of the pre-operational testing[3] of~~ a registered entity's ~~protective system equipment~~program.

~~**Reliability Objective**~~
~~The reliability objective of PRC-005-1 R2 is to ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested with the intervals defined in the registered entity's program.~~

Compliance Application
In order to determine compliance with PRC-005 R2, CEAs are instructed to look for evidence that substantiates the ~~Registered entities must be able to provide evidence to the Compliance Enforcement~~

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] Pre-operational testing may also be referred to as "commissioning tests." The "pre-operational test" means the last testing a registered entity conducts on the Protection System device before the device is put into service.
[3] ~~The "pre-operational test" means the last testing a registered entity conducts on the Protection System device before the device is put into service.~~

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

~~Authority (CEA) to substantiate the~~ last date ~~it a registered entity~~ tested and maintained its Protection System[4] devices. ~~in order to demonstrate its compliance with PRC-005-1 R2.~~

PRC-005-1 R2 ~~requires~~provides, in pertinent part:

> ***R2.*** *Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization[5] on request (within 30 calendar days). The documentation of the program implementation shall include:*
>
> ***R2.1.*** *Evidence Protection System devices were maintained and tested within the defined intervals.*
> ***R2.2.*** *Date each Protection System device was last tested/maintained.*

~~In order to determine whether a registered entity is conducting maintenance and testing within the intervals defined by its own Protection System maintenance and testing program, the CEA must have a substantiated last maintenance or test date.~~

Without evidence ~~to~~ demonstrat~~e~~ing that new equipment ~~had been~~was tested and was in appropriate condition to enter into service (the start date), a CEA cannot assess when the registered entity's ~~cannot provide the date it used as a starting point to determine when its first~~ maintenance or testing must occur. ~~according to the intervals defined by its Protection System maintenance and testing program.~~

As soon as the entity conducts its pre-operational testing[6], the interval begins for its ~~and puts the protective scheme into service,[7] the interval has begun for its~~ maintenance and testing program.[8] The completion of the pre-operational testing, not the initiation of the pre-operational testing, is the point in time that the registered entity is aware of the operating condition of the equipment. ~~and t~~Thus the completion date ~~is the~~ of the pre-operational testing is the date that should be used as the start~~ing point~~ date for the equipment's maintenance and testing interval. As pre-operational testing may occur over a period of time, the CEA is to verify the date that the pre-operational ~~registered entity should use the date that the pre-operational~~ testing was completed for the equipment at issue.

---

[4] The *NERC Glossary of Terms Used in Reliability Standards* defines Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry."
[5] For this standard, the Regional Reliability Organization refers to the Regional Entity.
[6] ~~Pre-operational testing may also be referred to as "commissioning tests".~~
[7] ~~The registered entity's Protection System maintenance and testing program is only applicable for Protection System devices in service; however the date the equipment was placed in-service is not the date that should be used for the starting point of the maintenance and testing interval, unless the equipment was placed into service on the same date the pre-operational testing was completed.~~
[8] The registered entity's Protection System maintenance and testing program is only applicable for Protection System devices in service; however the date the equipment was placed in-service is not the date that should be used for the starting point of the maintenance and testing interval, unless the equipment was placed into service on the same date the pre-operational testing was completed.

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

The next maintenance and testing date to be verified by the CEA would be at some specific period of time after the start date, ~~in the future from that start date,~~ as defined by the interval defined in the registered entity's maintenance and testing program.

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from April 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[9] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance ~~Guidance~~

~~As~~ To determine evidence of the start~~ing point~~ date for ~~its~~ a registered entity's equipment's maintenance and testing interval, a CEA is instructed to look for the date the registered entity completed its equipment's pre-operational testing that demonstrated that the equipment was deemed operational and ready to be placed into service. ~~must be able to provide an auditor or CEA with:~~

~~the date it completed its pre-operational testing, and~~

~~evidence that the equipment was deemed operational and cleared for entry into service.~~

In the event that a registered entity has equipment that ~~changed~~ changes status such that it becomes subject to the standard (such as a radial line becoming a non-radial line), a CEA is instructed to look for either:

1. the date existing Protection System devices were last maintained or tested, or
   the date the registered entity completed its equipment's pre-operational testing that demonstrated that the equipment was deemed operational and ready to be placed into service ~~new Protection System devices completed pre-operational testing,~~

~~will be~~as the start date for determining the equipment's maintenance and testing interval under the registered entity's maintenance and testing program. ~~A registered entity must be prepared to provide evidence of this date to the auditor or CEA.~~

For more information please contact:

Michael Moon

Valerie Agnew

[9] "Initiated" means that a registered entity has received notification of the upcoming audit.

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

Director of Compliance Operations

michael.moon@nerc.net
609-524-7028

Manager of ~~Compliance Standards~~ Interface and Outreach

valerie.agnew@nerc.net
609-524-7075

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
April 19, 2011	Posted Final CAN	
November 16, 2011	Posted Revised CAN	Revised target audience to CEA

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this compliance application notice is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

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

Industry Comments for CAN-0011

Comment Topics	Main Points	Industry Suggestions
Errata Changes	Make changes to CAN for clarity	Review various footnotes and sentences
Supports CAN	Supports CAN as written	CAN provides additional clarity
Scope	The CAN should be subject to NERC's formal standards development or interpretation process.	This issue is already being addressed through SDT Project 2012-04 Protection System Commissioning Testing.
Evidence of Compliance	The plain language of the Standard should be used to assess compliance.	The Registered Entity's intervals and basis have been defined in the Protection System maintenance and testing program, however, that program applies to new equipment when such equipment becomes operational or placed in service. This is not dependent on the pre-operational test date.
Effective Date	A reasonable implementation plan should be considered.	Longer timeframe to implement

Industry Comments for CAN-0012

Comment Topics	Main Points	Industry Suggestions
Supports CAN	Supports CAN as written	CAN provides additional clarity
Scope	An entity should only be required to perform periodic activities after the "compliant" date of a standard.	This CAN should be revised. A registered entity should not have to comply with a standard until the date on which the standard became effective for that entity.
Effective Date	Entities should be provided adequate time to adjust their programs, systems or hardware to conform to the instruction outlined in a CAN.	We request that NERC incoroporates a reasonable implementation period for all CANs.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0012 Comment Analysis Summary

Completion of Periodic Activity Requirements During Implementation Plan

CAN-0012 was originally posted as final on July 18, 2011. The original CAN provided instruction for assessing whether registered entities completed a periodic action in accordance with the implementation plan for a standard. The CAN has been revised to incorporate the direction provided by the NERC Board of Trustees in August of 2011 and was reposted as final on November 16, 2011.

The revised draft CAN was posted for industry comment on the NERC web site on October 10, 2011 and the comment period expired on October 31, 2011. NERC received some positive feedback from industry during the comment period, stating that CAN-0012 addresses a valid concern in the assessment of implementation plans.

NERC received approximately 19 comments from registered entities and three comments from trade associations, which are identified below. The main themes of the comments consisted of the following two categories: scope and effective date.

Scope

There were several recommended substantive changes to the CAN in regard to scope. The commenters stated that CAN-0012 goes beyond the requirements in the standards, and Compliance Enforcement Authority (CEA) staff should not be instructed to verify evidence prior to the "compliant" date. The rationale was that a registered entity should not have to comply with a standard until the date on which the standard became effective for that entity.

In response to the comments, CAN-0012 was drafted to provide direction to CEAs on how to assess compliance in regard to periodic activities required by the standard. The implementation plan for a standard provides time for a registered entity to become compliant with the standard. As of the effective date of that standard for the registered entity, a CEA is to verify that the registered entity is compliant with requirements of a standard, which includes compliance with the requirement to conduct periodic activities.

Effective Date

Several commenters believe that NERC should incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted by NERC as final and provides in that posting an implementation and effective date, which cannot be earlier than the posted date. There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

CEAs assess compliance according to the CAN upon posting of the CAN as final on the NERC web site. This specific CAN had been posted as final on July 18, 2011; as the compliance application in the redrafted CAN did not impose any additional evidentiary burden on registered entities, the use of the compliance application continues from the original posting date. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

Conclusion

The analysis spreadsheet for CAN-0012 has been posted on the NERC website. NERC received feedback that the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments. In order to provide increased transparency to the comment analysis phase of the CAN process, this document has been created to supplement the information contained in the spreadsheet. NERC staff thanks industry members for the time and effort put into providing the comments and feedback for CAN-0012. If you would like further discussion on CAN-0012, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
Austin Energy
Bonneville Power Administration (BPA)
Constellation Energy (CEG)
Consumers Energy
Dominion Resources Services, Inc.
Duke Energy
Farmington Electric Utility System (FEUS)
First Energy (FE)
Ingleside Cogeneration/Occidental
Kansas City Power and Light (KCP&L)
Manitoba Hydro
MidAmerican Energy Company
Oncor Electric Delivery
Pepco Holdings, Inc.
PSEG
Southern Company
Xcel Energy

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)

ISO/RTO Council Standards Review Committee (IRS SRC)
NPCC Entities (industry)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0012

Completion of Periodic Activity Requirements During Implementation Plan

Posted: July 18, 2011
Revised: November 16, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Registered Entity

Issue: Under what circumstances should a CEA verify completion of a periodic action or event during the implementation plan of a new or revised standard?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether registered entities performed a periodic action in accordance with the implementation plan for a standard.

Compliance Application
In the event that a standard that is subject to an implementation plan, such as the CIP-002 through CIP-009 standards, contains a requirement of a periodic action or event, CEAs are to verify that the first occurrence of the periodic action or event was completed on or before the "compliant" date that applies to the particular registered entity, unless otherwise specified in the standard. For the CIP standards, "compliant" means that a registered entity meets the full intent of the requirements and is beginning to maintain required "data," "documents," "documentation," "logs," and "records." The CEA is to review the required data, documents, documentation, logs and records to verify compliance with the requirement for the recurring periodic actions or events.

Example 1
A standard indicated a "compliant" date of August 1, 2011 for a particular registered entity and required an annual activity.[2] In the event that, on January 1, 2012, a registered entity completed a self-certification for this standard, the CEA is to have looked at the date that it completed the activity.

1. If the registered entity had not performed the activity at least once on or before the "compliant" date of August 1, 2011, the CEA is to find a Possible Violation of the standard from

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards and requirements.
[2] In cases where the standard contains a definition of the term "annual" or "annually," that definition remains and is applicable to that standard. In all standards where the term "annual" is not defined, CEAs are to assess compliance by determining the entity's definition of annual within the parameters provided in CAN-0010 Definition of Annual, provided the action or activity was performed prior to the registered entity's Effective Date for the Standard.

August 1, 2011 until the date the registered entity completed the activity. Even if the registered entity had performed the annual activity after the ”compliant” date of the standard, the entity would be considered non-compliant.

2. If the registered entity performed the activity on or before August 1, 2011, the CEA is to determine that the entity did not have a non-compliance with the standard. Because the requirement was for an annual activity, if the entity had performed the activity between January 1, 2011, and August 1, 2011, the registered entity would have had until December 31, 2012 to complete the recurring activity. However, as stated in CAN-0010 Definition of Annual, it is a best practice not to have more than 15 months pass between events that must occur on an annual basis.

Example 2

A standard indicated a “compliant” date of August 1, 2011 for a particular registered entity, and required an activity to be completed every three months. In the event that, on January 1, 2012, a registered entity completed a self-certification for this standard, a CEA is to have looked at the date that it completed the activity.

1. If the registered entity completed the required periodic activity after the “compliant” date of August 1, 2011, the CEA is to find a Possible Violation of the standard.
2. If the registered entity performed the periodic activity on August 1, 2011, and again on December 1, 2011 (four months between activities instead of the three-month requirement), the CEA is to find a Possible Violation from November 1, 2011 (the date that the next activity should have been completed) through December 1, 2011 (the date the activity was completed).

   The time between activities is important. The clock for the three-month interval begins once the last activity has been completed. In this example, the entity performed the activity on December 1, 2011, and would have until March 1, 2012 before the next activity needed to be performed.

   The violation would be due to the gap in compliance from November 1, 2011 through December 1, 2011.
3. If the registered entity performed the activity on June 1, 2011, September 1, 2011 and December 1, 2011, the entity would be in compliance with the standard, because it had performed the activity prior to the “compliant” date and every subsequent three-month period.
4. If the registered entity performed the activity on June 1, 2011 and November 1, 2011 and was scheduled to conduct the next activity on February 1, 2012, the entity would be non-compliant with the standard from September 1, 2011 through November 1, 2011 because the effective date (August 1, 2011) did not restart the clock for the three-month period. To be the compliant,

the entity would have to have been tested on June 1, 2011, September 1, 2011 and December 1, 2011 (as in example #3).

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from July 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the situation, in determining whether to assess compliance pursuant to this CAN.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
July 18, 2011	**Posted Final CAN**	
November 16, 2011	**Posted Revised CAN**	**Revised target audience to CEAs**

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Compliance Application Notice — 0012

Completion of Periodic Activity Requirements ~~Prior to a Registered Entity's Effective Date for a Standard~~During Implementation Plan

Posted: July 18, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entities
Registered Entities

Issue: Under what circumstances should a CEA verify completion of ~~Requirement for~~ a periodic action or event during the implementation plan of a new or revised ~~to be completed prior to a Registered Entity's effective date for a~~ Standard?

NERC received a request for clarification on whether a registered entity must provide evidence that it completed a periodic action or event required by a NERC Reliability Standard (Standard) prior to the registered entity's effective date[2] for the Standard.

~~**Reliability Objective**~~

~~The reliability objective is to ensure periodic actions or events required by a Standard have been completed during the registered entity's implementation period to demonstrate that the registered entity is compliant[3] upon its effective date for a Standard.~~

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standards and requirements.

[2] A registered entity's effective date is dependent upon the effective date of the Standard, the entity's registration date, and the Standard's implementation plan, as applicable. For example, in the NERC Critical Infrastructure Protection (CIP) Reliability Standards CIP-002 through CIP-009 versions 1, 2 and 3, a registered entity's effective date is the compliant date that is applicable to the registered entity in either the original Implementation Plan for CIP version 1 Standards or the *Newly Identified Critical Cyber Asset Implementation Plan* for version 2 and 3 Standards.

[3] ~~For the CIP standards, "compliant" is defined in 1) *The (Revised) Implementation Plan for Cyber Security Standards CIP-002-1 through CIP-009-1* and 2) *The Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities for Cyber Security Standards CIP-002-2 through CIP-009-2 and CIP-002-3 through CIP-009-3*, to mean the registered entity meets~~

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com
~~116-390 Village Blvd.~~
~~Princeton, NJ 08540~~
~~609.452.8060 | www.nerc.com~~

Compliance Application

In the event that a standard that is subject to an implementation plan, such as the CIP-002 – CIP-009 standards, contains a requirement of a periodic action or event, CEAs are to verify that the first ~~Where a Standard's requirements include a requirement for a periodic action or event, the first~~ occurrence of the ~~recurring~~ periodic action or event was completed on or before the "compliant" date that applies to the particular registered entity, unless otherwise specified in the standard. For the CIP standards, "compliant" means that a registered entity meets the full intent of the requirements and is beginning to maintain required "data," "documents," "documentation," "logs," and "records." The CEA is to review the required data, documents, documentation, logs and records to verify compliance with the requirement for the recurring periodic actions or events.~~requirement must be completed by the registered entity prior to the effective date of the standard.~~

Example 1

A standard indicated a "compliant" date of August 1, 2011 for a particular registered entity and required an annual activity.[4] In the event that, on January 1, 2012, a registered entity was completing a self-certification for this standard, the CEA is to look at the date that it completed the activity.

~~1) A registered entity must have conducted the required periodic action or event prior to the standard's effective date unless otherwise specified in a Standard; and~~

1. If the registered entity had not performed the activity at least once on or before the "compliant" date of August 1, 2011, the CEA is to find a Possible Violation of the standard from August 1, 2011 until the date the registered entity completed the activity. Even if the registered entity had performed the annual activity after the "compliant" date of the standard, the entity would be considered non-compliant.
2. If the registered entity performed the activity on or before August 1, 2011, the CEA is to determine that the entity did not have a non-compliance with the standard. Because the requirement was for an annual activity, if the entity had performed the activity between January 1, 2011, and August 1, 2011, the registered entity would have had

~~the full intent of the requirements and is beginning to maintain required "data," "documents," "documentation," "logs," and "records."~~

[4] In cases where the standard contains a definition of the term "annual" or "annually," that definition remains and is applicable to that standard. In all standards where the term "annual" is not defined, CEAs are to assess compliance by determining the entity's definition of annual within the parameters provided in CAN-0010 Definition of Annual, provided the action or activity was performed prior to the registered entity's Effective Date for the Standard.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

until December 31, 2012 to complete the recurring activity. However, as stated in CAN-0010 Definition of Annual, it is a best practice not to have more than 15 months pass between events that must occur on an annual basis.

~~2) A Responsible Entity must have sufficient evidence for an auditor to validate that the action or event was completed.~~

Example 2

A standard indicated a "compliant" date of August 1, 2011 for a particular registered entity, and required an activity to be completed every three months. In the event that, on January 1, 2012, a registered entity was completing a self-certification for this standard, a CEA is to look at the date that it completed the activity.

~~Following its effective date, the registered entity is required to collect and maintain required "data," "documents," "documentation," "logs," and "records" to demonstrate compliance with the requirement for the recurring periodic actions or events.~~

1. If the registered entity completed the required periodic activity after the "compliant" date of August 1, 2011, the CEA is to find a Possible Violation of the standard.
2. If the registered entity performed the periodic activity on August 1, 2011, and again on December 1, 2011 (four months between activities instead of the three-month requirement) the CEA is to find a Possible Violation from November 1, 2011 (the date that the next activity should have been completed) through December 1, 2011 (the date the activity was completed).

   The importance is the time between activities. The clock for the three-month interval begins once the last activity has been completed. In this example, the entity performed the activity on December 1, 2011, and would have until March 1, 2012 before the next activity needed to be performed.

   The violation would be due to the gap in compliance from November 1, 2011 through December 1, 2011.
3. If the registered entity performed the activity on June 1, 2011, September 1, 2011 and December 1, 2011 the entity would be in compliance with the standard, because it had performed the activity prior to the "compliant" date and every subsequent three-month period.
4. If the registered entity performed the activity on June 1, 2011 and November 1, 2011 and was scheduled to conduct the next activity on February 1, 2012, the entity would be non-compliant with the standard from September 1, 2011 through November 1, 2011 because the effective date (August 1, 2011) did not restart the clock for the three-

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

month period. To be the compliant, the entity would have to have tested on June 1, 2011, September 1, 2011 and December 1, 2011 (as in example #3).

~~**Examples:**~~

1. ~~A Standard became effective July 1, 2010, and required an annual activity.[5] In the event that, on January 1, 2011 a registered entity was completing a self-certification for this Standard, it would look at the date that it completed the activity.~~

    a. ~~If the registered entity had not performed the activity at least once prior to the effective date of July 1, 2010, it would be in violation of the Standard from the effective date until the date the registered entity completed the activity. Even if the registered entity had performed the annual activity once in the calendar year, if it was performed after the effective date of the Standard, the entity would be considered non-compliant.~~

    b. ~~If the registered entity performed the activity between January 1, 2010 and July 1, 2010, the entity would be in compliance with the Standard. Because the requirement was for an annual activity, the registered entity had until the next December 31, 2011 to complete the recurring activity. However, as stated in CAN-0010 Definition of Annual it is a best practice to not have more than 15 months between events; therefore, it would be prudent for the registered entity to complete the activity by June 15, 2011.~~

2. ~~A Standard became effective on July 1, 2010 and required an activity to be completed every three months. In the event that, on January 1, 2011 a registered entity was completing a self-certification for this standard covering the prior year, it would look at the date that it completed the activity.~~

    a. ~~If the registered entity completed the required periodic activity after the effective date of July 1, 2010, it would be in violation of the Standard.~~

    b. ~~If the registered entity performed the periodic activity on June 15, 2010 and again on October 15, 2010 the entity would be in violation from September 15, 2010 (the date that the next activity should have been completed) through October 15, 2010 (the date the activity was completed). The entity would have until January 15, 2010 before the next activity needed to be performed. This violation would be due to the gap in compliance from September 15, 2010 through October 15, 2010. The effective date does not restart the clock for the three-month period.~~

Formatted: Font: 12 pt

[5] ~~In cases where the standard contains a definition of the term "annual" or "annually," that definition remains and is applicable to that standard. In all standards where the term "annual" is not defined, the registered entity may determine its definition of annual within the parameters provided in CAN-0010 Definition of Annual, provided the action or activity was performed prior to the registered entity's Effective Date for the Standard.~~

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

~~c. If the registered entity performed the activity on June 15, 2010, September 15, 2010 and December 15, 2010 the entity would be in compliance with the Standard because it had performed the activity prior to the effective date and every subsequent three-month period.~~

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from July 19, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[6] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the situation, in determining whether to assess compliance pursuant to this CAN~~This CAN is effective upon posting on the NERC Web site and will remain in effect until such time that a future version of the standard or interpretation addresses this specific issue and is enforceable. CAN-0012 could be superseded by a future CAN that addresses this particular Standard and Requirement~~.

For more information please contact:

Michael Moon
Director of Compliance Operations

Michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of ~~Compliance Standards~~ Interface and Outreach

Valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

[6] "Initiated" means that a registered entity has received notification of the upcoming audit.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

Posted Date	Action	Revision
July 18, 2011	Posted Final CAN	
Month 16, 2011	Posted Revised CAN	Revised target audience to CEAs

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this compliance application notice is not a substitute for compliance with requirements in NERC's Reliability Standards.*~~

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

Industry Comments for CAN-0013

Comment Topics	Main Points	Industry Suggestions
Supports CAN	Supports CAN as written	No changes
Errata Changes	Leave the version of the standard instead of removing it, in the title.	Suggests leaving the version of the standard (in this case PRC-023-1, as opposed to PRC-023) as it specifically identifies the version of the standard to which it applies and it also conforms to most other CANS that have been previously issued.
Effective Date	When does the PC need to establish this initial list?	According to PRC-023 R3 the Planning Coordinator needs to make a list of facilities 100kV to 200kV that are critical to the reliability of the BES. R3.3 states that the PC needs to deliver this list to the RCs, TOs, GOs, and DPs within 30 days of the establishment of the initial list.
Evidence of Compliance	CAN-0013 is changing the clear language of the Standard and hence changing the requirements of the Standard which should be prohibited based on Rules of Procedure. PRC-023-2 has been written in more detail and addresses this concern.	Until PRC-023-2 is approved PRC-023-1 should stand as approved.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0013 Comment Analysis Summary

PRC-023 R1 and R2 Effective Dates for Switch-On-To-Fault Schemes

CAN-0013 was originally posted as final on June 17, 2011. The original CAN clarified the effective dates for switch-on-to-fault (SOTF) schemes under PRC-023 R1 and R2. The CAN has been revised to incorporate the direction provided by the NERC Board of Trustees in August of 2011 and was reposted as final on November 16, 2011.

The revised draft CAN was posted for industry comment on the NERC web site on October 10, 2011, and the comment period expired on October 31, 2011. NERC received a few positive comments from industry members, stating that the clarifications provided in CAN-0013 were acceptable as written.

NERC received approximately nine comments from registered entities and three comments from trade associations, which are identified below. The main themes of the comments consisted of the following four categories: errata changes, issue statement, effective date and evidence of compliance.

Errata

There was a comment about the version of the standard not being listed, which may cause confusion if a future standard is approved and becomes effective.

We acknowledge that the version has been removed from the standard (PRC-023-1 now reads PRC-023), and this change was intentional for efficiency and to avoid any potential gaps in compliance monitoring. The change was made to ensure that the message of the CAN remained intact in the event that a revised standard or interpretation became enforceable that did not address the issue in the CAN. As mentioned in the effective date section, if an enforceable revised standard or interpretation addresses the issue in a CAN, the CAN will be superseded by the standard.

Scope

Several commenters made recommendations to change the effective date section of CAN-0013. They stated that although the CAN was developed to specifically address the effective dates relevant to "switch-on-to-fault schemes," they suggest for clarity that NERC include the effective date for requirements included in 5.1.3. This CAN was not expanded to include the effective dates for R5.1.3, but NERC staff will investigate whether this information can be included on the Standards Mandatory and Effective Dates page on the NERC website.

Effective Date

Several commenters said that NERC should incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted

by NERC as final and provides in that posting an implementation and effective date, which cannot be earlier than the posted date. There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

The effective date for CAN-0013 remains June 17, 2011, the same date as the original posting. This is because the change to the CAN did not materially revise the compliance application in the previously posted version, and therefore the compliance application is a continuation of the original compliance application. Both dates of final posting are included on the final CAN.

Evidence of Compliance

Other commenters stated that CAN-0013 changes the clear language of the standard requirements, which should be prohibited based on the Rules of Procedure. PRC-023-2 has been written in more detail and addresses this concern, and until PRC-023-2 is approved, PRC-023-1 should stand as approved.

It is understood that another version of PRC-023 is currently being drafted, but the ERO has an obligation to monitor compliance to the current, enforceable standards. CAN-0013 provides additional clarity and promotes consistency with CEA staff for compliance monitoring activities. When PRC-023-2 becomes mandatory and enforceable, if it resolves the issue, CAN-0013 will be superseded and retired.

Conclusion

The analysis spreadsheet for CAN-0013 has been posted on the NERC website. NERC received feedback that the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments. In order to provide increased transparency to the comment analysis phase of the CAN process, this document was created to supplement the information contained in the spreadsheet. NERC staff thanks industry members for the time and effort put into providing the comments and feedback for CAN-0013. If you would like further discussion on CAN-0013, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Public Power Association (APPA)
Bonneville Power Administration (BPA)
Dominion Resources Services, Inc.
Kansas City Power and Light (KCP&L)
MidAmerican Energy Company
Oncor Electric Delivery
Pepco Holdings, Inc.
PSEG

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
National Rural Electric Cooperative Association (NRECA)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice – 0013

PRC-023 R1 and R2 Effective Dates for Switch-On-To-Fault Schemes

Posted: June 17, 2011
Revised: November 16, 2011

Primary Interest Groups

Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Transmission Owners (TO), Generation Owners (GO), Distribution Providers (DP) and Planning Coordinators (PC) with load-responsive phase protection systems subject to NERC Reliability Standard PRC-023

Issue: What are the Effective Dates for switch-on-to-fault (SOTF) schemes?

For the purpose of aiding a CEA, this CAN clarifies the Effective Dates for SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, under PRC-023 Requirement (R) 1 and R2.

Background

Points 5.1.1 and 5.1.2 of the introduction to the standard set forth the effective dates for equipment applicable to R1 and R2. The language reads:

> ***5.1.1*** *For circuits described in 4.1.1[2] and 4.1.3[3] above (except for switch-on-to-fault schemes) — the beginning of the first calendar quarter following applicable regulatory approvals.*
>
> ***5.1.2*** *For circuits described in 4.1.2[4] and 4.1.4[5] above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.*

The Standard Drafting Team included a parenthetical in PRC-023 R5.1.2 to address comments from industry participants that "[t]he schedule for switch-on-to-fault (SOTF) protections applied on elements 200 kV and above is the same as the Beyond Zone 3 schedule for the phase protections referenced in

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] Transmission lines operated at 200 kV and above.
[3] Transformers with low voltage terminals connected at 200 kV and above.
[4] Transmission lines operated at 100 kV to 200 kV as designated by the PC as critical to the reliability of the Bulk Power System (BPS).
[5] Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the PC as critical to the reliability of the BPS.

section A.4.1.2 and A.4.1.4 applied on elements 100 kV to 200 kV. The Effective Date for the standard should be modified to include all SOTF protections in the Effective Date in Section A.5.1.2."

Compliance Application

The Effective Date for SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, is the beginning of the first calendar quarter 39 months following applicable regulatory approvals. CEAs are to assess compliance as of the applicable Effective Date.

To summarize, the Effective Dates corresponding to the applicable equipment under points 5.1.1 and 5.1.2 of the introduction to PRC-023 are as follows:

Equipment	Effective Date	US Effective Date
Transmission lines operated at 200 kV and above (except SOTF schemes)	the beginning of the first calendar quarter following applicable regulatory approvals	July 1, 2010
Transformers with low voltage terminals connected at 200 kV and above (except SOTF schemes)		
Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.	the beginning of the first calendar quarter 39 months following applicable regulatory approvals	October 1, 2013
Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System		
SOTF schemes on all applicable facilities specified in the applicability sections A.4.1.1 – A.4.1.4		

Effective Period for CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[6] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
June 17, 2011	**Posted Final CAN**	
November 16, 2011	**Posted Revised CAN**	**Revised target audience to CEAs**

[6] "Initiated" means that a registered entity has received notification of the upcoming audit.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0013

~~Compliance Application:~~ PRC-023-1 R1 and R2 Effective Dates for Switch-On-To-Fault Schemes

Posted June 17, 2011
Revised: November 16, 2011

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional ~~Entities~~Entity
Transmission Owners (TO), Generation Owners (GO), Distribution Providers (DP) and Planning Coordinators (PC) with load-responsive phase protection systems subject to NERC Reliability Standard PRC-023-~~1~~[2]

Issue: What are the ~~Clarification of the~~ Effective Dates for ~~Switch~~switch-~~On~~on-~~To~~to-~~Fault~~ fault (SOTF) ~~Schemes~~schemes?
For the purpose of aiding a CEA, this CAN clarifies the Effective Dates for ~~NERC received a request to clarify the effective date for switch-on-to-fault schemes~~ SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, under PRC-023-~~1~~ Requirement (R) 1 and R2.

~~Reliability Objective~~
~~To facilitate compliance with NERC Reliability Standards through the clear communication of effective dates.~~

Background
Points 5.1.1 and 5.1.2 of the introduction to the standard set forth the effective dates for equipment applicable to R1 and R2. The language reads:

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] ~~PRC-023-1 was approved by the Federal Energy Regulatory Commission in Order No. 733, which was effective on May 17, 2010. See Transmission Relay Loadability Reliability Standard, Order No. 733, 130 FERC ¶ 61,221 (2010).~~

3353 Peachtree Rd NE
Suite 600, North Tower
Atlanta, GA 30326
404/446-2560 | www.nerc.com

Formatted: Indent: Left: -0.5"
Formatted: Font: 12 pt
Formatted: Font: 12 pt
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt

5.1.1 *For circuits described in 4.1.1[3] and 4.1.3[4] above (except for switch-on-to-fault schemes) —the beginning of the first calendar quarter following applicable regulatory approvals.*

5.1.2 *For circuits described in 4.1.2[5] and 4.1.4[6] above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.*

The ~~standard~~ Standard ~~drafting~~ Drafting ~~team~~ Team included a parenthetical in PRC-023 R5.1.2~~,~~ to address comments from industry participants that "[t]he schedule for ~~Switch~~switch-~~On~~on-~~To~~to-~~Fault~~ fault (SOTF) protections applied on elements 200 kV and above is the same as the Beyond Zone 3 schedule for the phase protections referenced in section A.4.1.2 and A.4.1.4 applied on elements 100 kV to 200 kV. The Effective Date for the ~~Standard~~ standard should be modified to include all SOTF protections in the Effective Date in Section A.5.1.2."

Compliance Application

The ~~effective~~ Effective ~~date~~ Date for ~~switch-on-to-fault~~SOTF schemes included on 1) transmission lines operated at 200 kV and above, and 2) transformers with low voltage terminals connected at 200 kV and above, is the beginning of the first calendar quarter 39 months following applicable regulatory approvals. CEAs are to assess compliance as of the applicable Effective Date.

To summarize, the ~~effective~~ Effective ~~dates~~ Dates corresponding to the applicable equipment under points 5.1.1 and 5.1.2 of the introduction to PRC-023~~-1~~ are as follows:

Equipment	Effective Date	US Effective Date
Transmission lines operated at 200 kV and above (except ~~switch-on-to-fault~~SOTF schemes)	the beginning of the first calendar quarter following applicable regulatory approvals	July 1, 2010
Transformers with low voltage terminals connected at 200 kV and above (except ~~switch-on-to-fault~~SOTF schemes)		
Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.	the beginning of the first calendar quarter 39 months following applicable regulatory approvals	October 1, 2013
Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System		
~~Switch-on-to-fault~~SOTF schemes on all applicable facilities specified in the applicability sections A.4.1.1		

[3] Transmission lines operated at 200 kV and above.
[4] Transformers with low voltage terminals connected at 200 kV and above.
[5] Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Power System.
[6] Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

Formatted: Font: 12 pt, Italic, Not Superscript/ Subscript
Formatted: Font: 12 pt, Not Bold, Italic, Not Superscript/ Subscript
Formatted: Font: 12 pt, Not Bold, Italic
Formatted: Font: 12 pt, Not Bold, Italic, Not Superscript/ Subscript
Formatted: Font: 12 pt, Not Bold, Italic
Formatted: Font: 12 pt, Not Bold, Italic, Not Superscript/ Subscript
Formatted: Font: 12 pt, Not Bold, Italic
Formatted: Font: 12 pt, Italic, Not Superscript/ Subscript
Formatted: Font: 12 pt, Not Bold, Italic, Not Superscript/ Subscript
Formatted: Font: 12 pt, Not Bold, Italic
Formatted: Font: 12 pt, Not Bold, Italic, Not Superscript/ Subscript
Formatted: Font: 12 pt, Not Bold, Italic
Formatted: Font: 12 pt, Not Bold, Italic, Not Superscript/ Subscript
Formatted: Font: 12 pt, Not Bold, Italic
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt
Formatted: Font: 12 pt, Not Superscript/ Subscript
Formatted: Font: 12 pt

– A.4.1.4.		

Effective Period of CAN

This revised CAN supersedes the original CAN, as well as all prior communications. CEAs are to use this CAN to assess compliance from June 17, 2011, regardless of the start date of the violation. It will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[7] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

~~**Possible Compliance Actions**~~

~~This CAN clarifies PRC-023-1 and thus will be applicable during the same time period as the PRC-023-1 standard is effective.~~

For more information please contact:

Michael Moon
Director of Compliance Operations

Michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of ~~Compliance Standards~~ Interface and Outreach
Valerie.agnew@nerc.net
404-446-2566

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

Revision History

Posted Date	Action	Revision
June 17, 2011	Posted Final CAN	
November 16, 2011	Posted Revised CAN	Revised target audience to CEA

~~*This document is designed to convey compliance guidance from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time.*~~

[7] "Initiated" means that a registered entity has received notification of the upcoming audit.

Comment [A1]: MRO NSRF: NERC continues to ignore industry and EEI comments that CANs cannot and should not use retroactive compliance dates. Because any clarification changes, at a minimum how NERC standards are applied, entities must be allowed time to review and change their practices if needed. It is wrong to used retroactive dates.

Comment [A2]: ERCOT: As written, the CAN is imposing an effective date prior to the posting date. The effective date should be the posting date of the final CAN. Any reference prior to that is not meaningful since the evidence guideline provided in the final CAN should be applicable going forward, not backward.

Comment [A3]: NRECA: Although the CAN was developed to specifically address the effective dates relevant to "switch-on-to-fault schemes", NRECA suggests for clarity that that NERC include the effective date for requirements included in 5.1.3.

Formatted: Font: 12 pt, Not Superscript/ Subscript

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Comment [A4]: KCP&L: KCP&L does not agree with the CAN-013 regarding the potential intention of the applicability and effective dates established by Standard PRC-023-1. Standard PRC-023 may be in error, but the CAN-0013 is changing the clear language of the Standard and hence changing the requirements of the Standard which should be prohibited based on Rules of Procedure. PRC-023-2 has been written in more detail and addresses this concern. Until PRC-023-2 is approved PRC-023-1 should stand as approved.

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Formatted: Font: 12 pt, Not Superscript/ Subscript

Comment [A5]: ERCOT: by using phrases such as "are to use this CAN to assess compliance" and "apply appropriate discretion," the "Effective Period" section implies that the guidance provided in the CAN is mandatory, despite the fact that the CAN is not developed through the Standards Development Process, not balloted and not approved by government authorities. The SRC recommends not using the terms "compliance," "non-compliance," or "assess," or "assessment."

Comment [A6]: ACES: The CAN does not fully satisfy the effective date issue because the CAN does not address A.5.1.3 in the Effectiv ...

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Formatted: Font: 12 pt

Formatted: Font: 12 pt

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0029

PRC-004 R1, R2 and R3 Protection System Misoperations

Posted [DATE]

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Transmission Owner (TO)
Generator Owner (GO)
Distribution Providers that own a Transmission Protection System (DP)

Issue: Does development of the common reporting template implemented by Electric Reliability Organization (ERO) - Reliability Assessment and Performance Analysis (RAPA) in 2011 modify the way in which compliance with PRC-004 will be measured?
For the purpose of aiding a CEA, this CAN provides instruction for assessing whether entities reported Protection System Misoperations as required by PRC-004.

Compliance Application
PRC-004 Requirements 1 - 3 provides:

> ***R1.*** *The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's[2] procedures developed for Reliability Standard PRC-003 Requirement 1.*
>
> ***R2.*** *The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.*

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard and requirements.
[2] Consistent with applicable FERC precedent, the term 'Regional Reliability Organization' in this context refers to the applicable Regional Entity.

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

R3. *The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.*

The Electric Reliability Organization (ERO)-Reliability Assessment and Performance Analysis (RAPA) common reporting template on misoperation reporting guidelines can be found at: http://www.nerc.com/docs/pc/rmwg/Protection_System_Misoperation_Reporting_Template_Final.xlsx

The revised Misoperation reporting guidelines, implemented by ERO-RAPA in 2011, do not modify or negate the requirements under PRC-004. However, if a Regional Reliability Organization (RRO) has adopted the ERO-RAPA guidelines as the RRO's procedures used to meet compliance with PRC-003 Requirement R1, then the guidelines developed by ERO-RAPA should be treated as the RRO procedure that responsible entities must follow to comply with PRC-004 Requirements R1 through R3.

Whether an RRO has adopted the ERO-RAPA reporting guidelines to meet compliance with PRC-003-1 Requirement R1 or not, CEAs are to look for evidence that entities required to comply with PRC-004-1 Requirement R1 and R2 1) analyzed all Protection System Misoperations in accordance with their RRO's latest procedures and 2) developed and implemented a Corrective Action Plan (CAP) for each Misoperation in accordance with their RRO's latest procedures. In addition, CEAs are to look for evidence that entities provided documentation of their Protection System Misoperations, analyses and CAPs according to the applicable RRO procedures in accordance with PRC-004-1 Requirement R3.

Effective Period for CAN

This CAN is effective upon posting as final on the NERC Web site, and is to be used by CEAs to assess compliance from the posting date forward, regardless of the start date of any non-compliance or Possible Violation. It supersedes all prior communications and will remain in effect until such time that a future version of a FERC-approved or other applicable government authority-approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

A CEA is to assess the following to obtain reasonable assurance of the entity's compliance:

- the entity's record of all Protection System Misoperations analyses, and
- evidence the entity implemented a CAP in response to each Misoperation, and
- evidence that entities provided documentation of their Protection System Misoperations, analyses and Corrective Action Plans according to the applicable RRO procedures.

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

Caroline Clouse
Interface and Outreach Specialist
caroline.clouse@nerc.net
404-446-2560

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0029 Comment Analysis Summary

PRC-004 R1, R2 and R3 Protection System Misoperations

CAN-0029 provides instruction for assessing whether entities reported Protection System Misoperations as required by PRC-004. This CAN was posted for industry comment on September 23, 2011 through October 14, 2011. NERC received ten comments from registered entities and one comment from a trade organization as listed below.

Six of the 11 commenters, including the trade organization, supported the CAN. The remaining comments concerned the scope and the compliance application contained in the CAN, and was addressed as follows:

Scope

There was one comment submitted that requested the version of the standard be included in the CAN, and this was not changed as the version number was intentionally not included for efficiency. A CAN is superseded by a revised standard or interpretation that addresses the issue in the CAN and will be retired. If the issue is not addressed in the revised standard or interpretation, the CAN remains the compliance application to be used by Compliance Enforcement Authorities (CEAs), which would not be the case if the CAN was limited to a specific version. The same is true if the issue is mapped to another requirement or standard; if the issue is addressed the CAN is superseded and will be retired.

Compliance Application

There were four comments submitted for the Compliance Application section. Two addressed the RRO procedure, stating that it CAN should clearly state that the ERO-RAPA reporting process is not the defacto RRO procedure referenced in PRC-003. The CAN does not specifically state that the ERO-RAPA procedure is not the defacto RRO procedure, but states:

> The revised Misoperation reporting guidelines, implemented by ERO-RAPA in 2011, do not modify or negate the requirements under PRC-004. However, if a Regional Reliability Organization (RRO) has adopted the ERO-RAPA guidelines as the RRO's procedures used to meet compliance with PRC-003 Requirement R1, then the guidelines developed by ERO-RAPA should be treated as the RRO procedure that responsible entities must follow to comply with PRC-004 Requirements R1 through R3.

It was determined that this language conveys the message requested by the commenters.

The other two comments requested the sentence "developed and implemented a Corrective Action Plan (CAP) for each Misoperation in accordance with their RRO's **latest procedures**" be clarified to state

instead "developed and implemented a Corrective Action Plan (CAP) for each Misoperation in accordance with their RRO's **procedures that are valid at that time**." The intent of the CAN was not to require an entity to develop and implement a CAP for misoperations that occurred in the past for every change in RRO reporting procedures and the language was modified in the CAN.

Conclusion

The analysis spreadsheet for CAN-0029 is also posted on the NERC website. While the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments, it is hoped that this document will supplement that information. Feedback from all sources is key and NERC staff thanks industry for the time and effort put into providing that feedback. If you would like further discussion on CAN-0029, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
Bonneville Power Administration (BPA)
Kansas City Power & Light (KCP&L)
Madison Gas and Electric
MidAmerican Energy Company
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
Occidental/Ingleside Cogeneration LP
Pepco Holding, Inc.
Progress Energy (PGN)
Westar Energy

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)

Industry Comments for CAN-0029		
Comment Topics	**Main Points**	**Industry Suggestions**
Scope	PRC-004 cannot be modified by the reporting template established by the ERO-RAPA.	A standard cannot be modified outside the NERC Standards Development Process.
Effective Date	The CAN does not have an implementation period.	There are several typical things that all CANs should include, an implementation period being one of them.
Supports CAN	This CAN is appropriate and acceptable.	We find the approach used in CAN-0029 to be in-line with our vision for CANs.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0039

EOP-004-1 Filing DOE Form OE-417 Event Reports

Posted [DATE]

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Reliability Coordinator (RC)
Balancing Authority (BA)
Transmission Operator (TOP)
Generator Operator (GOP)
Load Serving Entity (LSE)
Regional Reliability Organization

Issue: Does the Department of Energy's (DOE) new online process affect the EOP-004 requirement for a registered entity to submit the OE-417 disturbance report to NERC?
The Department of Energy's (DOE) new online process for submitting the OE-417 disturbance reporting form does not automatically issue a copy to NERC or the Regional Entities.

Background
The DOE's Electric Emergency Incident and Disturbance Report (Form OE-417) collects information on electric incidents and emergencies. The DOE uses the information to fulfill its overall national security and energy emergency management responsibilities, as well as for analytical purposes. Beginning January 2011, the DOE initiated a new process by which entities are to submit OE-417 reports for qualifying events. Entities may now go to the DOE web site and fill out an online form for submission. The DOE online process tool does not distribute a copy of the report, either simultaneously or at a later time, to NERC. Therefore, NERC and the Regional Entities have no record of the event. **Compliance Application**
EOP-004-1, Table 1-EOP-004-0 states, in pertinent part:

> *All entities required to file a DOE OE-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.*

[1]Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30328
404.446.2560 | www.nerc.com

DRAFT

EOP-004-1 R3 provides, in pertinent part:

> ***R3.*** *A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.*
>
> > ***R3.1.*** *The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.*
> >
> > ***R3.2.*** *Applicable reporting forms are provided in Attachments 1-EOP-004 and 2-EOP-004.*
> >
> > ***R3.3.*** *Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.*

DOE's institution of a new process does not provide an exemption to EOP-004. Regardless of how registered entities fulfill their DOE requirement (through the online submission tool or in another manner), CEAs are to look for evidence that entities submitted either

1) a copy of the on-line OE-417 report or

2) an off-line form pursuant to R3.2

to NERC at ESISAC@nerc.com and to the entity's Regional Entity within 24 hours of the disturbance or unusual occurrence, or as otherwise required by the standard, to fulfill the requirements of EOP-004-1. In the event that the CEA finds a registered entity did not submit a report to NERC, a CEA is to find a Possible Violation of EOP-004-1.

In the event registered entities submitted an OE-417 report online between January 2011 and posting of this CAN as final on the NERC web site, and did not provide NERC with a copy, registered entities are encouraged to submit the information from these reports to NERC at ESISAC@nerc.com.

Effective Period for CAN

This CAN is effective for EOP-004-1 upon posting as final on the NERC Web site, and is to be used by CEAs to assess compliance from the posting date forward, regardless of the start date of any non-compliance or Possible Violation. It supersedes all prior communications and will remain in effect until such time that a future version of a FERC-approved or other applicable government authority-approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30328
404.446.2560 | www.nerc.com

For any enforcement action in process and for audits that have been initiated,[2] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Providing Evidence of Compliance
CEAs are to look for evidence that entities provided a report to the appropriate Regional Entity and NERC within 24 hours of the disturbance or unusual occurrence, or as otherwise required by EOP-004.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

Caroline Clouse
Compliance Interface and Outreach Specialist
caroline.clouse@nerc.net
404-446-2588

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

[2] "Initiated" means that a registered entity has received notification of the upcoming audit.

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30328
404.446.2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0039 Comment Analysis Summary

EOP-004 R3 Filing DOE Form OE-417 Event Reports

CAN-0039 provides clarification that the online process for submitting Department of Energy's (DOE) OE-417 disturbance reporting form does not allow for multiple parties to receive the report automatically. The CAN was posted for industry comment on the NERC web site on September 23, 2011 and the comment period expired on October 14, 2011.

NERC received approximately 15 comments from various industry stakeholders and trade associations, which are identified by name below. The main themes of the comments consisted of the following three categories: errata changes, scope of CAN and a suggestion for NERC to coordinate the reporting process with the DOE. There were also a few comments in support of the position in CAN-0039.

Errata

The recommended errata change was to add 'reporting requirements' to the end of the following statement, "DOE's institution of a new process does not provide an exemption to EOP-004." This change was made to the CAN as requested.

Scope

There two industry groups that recommended substantive changes to the CAN in regard to scope. The commenters stated that CAN-0039 goes beyond the language of EOP-004 and Compliance Enforcement Authority (CEA) staff should not be instructed to verify evidence that Form OE-417 was submitted to NERC because the DOE reporting procedure is not part of the requirement.

This CAN is to ensure that disturbances are being sent to NERC and the Regional Entities as required by EOP-004. Although the Requirement does not state the DOE form explicitly, it was brought to NERC's attention that some entities were under the impression that, by submitting the online DOE submittal process that a copy of that report would be sent to NERC and the Regional Entity. The CAN was issued to make CEA staff aware that the form is not automatically sent to NERC and the Regional Entities and additional steps must be taken to ensure proper delivery.

NERC to Coordinate with DOE

Several commenters suggested that NERC work with the DOE to streamline the process and make the online submittal of OE-417 as seamless as possible to reduce the administrative burden of saving a copy and sending it to NERC and the Regional Entities. NERC is currently working with DOE to allow for multiple parties to receive the report. While that process has not been implemented, it is thought that, when it is implemented, it will not occur automatically, but will required a registered entity to check a box to have the reports sent to other parties (including the Regional Entity and NERC). In the interim,

registered entities should be submitting OE-417 Forms to DOE, NERC and the applicable Regional Entity.

Conclusion

The analysis spreadsheet for CAN-0039 is also posted on the NERC website. While the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments, it is hoped that this document will supplement that information. Feedback from all sources is key and NERC staff thanks industry for the time and effort put into providing that feedback. If you would like further discussion on CAN-0039, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
Bonneville Power Administration (BPA)
Constellation Energy (CEG)
Dominion Resources Services, Inc.
Ingleside Cogeneration/Occidental
Kansas City Power & Light (KCP&L)
Madison Gas and Electric
MidAmerican Energy Company
Northwestern Energy
Pepco
Southern Company
Westar Energy

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
National Rural Electric Cooperative Association (NRECA)

Industry Comments for CAN-0039		
Comment Topics	**Main Points**	**Industry Suggestions**
Errata Changes	Add language for clarity	Suggest adding 'reporting requirements' to the end of the following statement; " DOE's institution of a new process does not provide an exemption to EOP-004."
Scope	The DOE reporting procedure is not part of the requirement.	The DOE online reporting process allows only one opportunity to save the report before submission and the submitted report cannot be retrieved, it only makes sense to allow the registered entity to submit a separate NERC report if necessary to comply. A registered entity should not be put in a position that a potential violation of a standard could occur because of the creation of the DOE on-line submission tool.
Supports CAN	This CAN is appropriate and acceptable.	CAN-0039 appropriate and acceptable as written as well as consistent with the original intent of the Standard. EEI also commends NERC in their efforts to make this CAN technically accurate, informationally sound and in line with the vision of CANs.
NERC to coordinate with DOE	Encourage NERC to work with DOE to gain direct access to the reports which would eliminate this whole issue and the need for the registered entity to report information twice.	Suggest that the DOE modify the form to include a drop down list that would allow reporting parties to select the region that they are in and this selection would automatically send the form to DOE, NERC, and the Regional Entity.

Industry Comments for CAN-0031		
Comment Topics	**Main Points**	**Industry Suggestions**
Errata Changes	Minor changes to CAN	Suggest changing language for consistency and fixing typos.
Scope	The Standards themselves do not dictate the type of material(s) that must be used to meet compliance, and various materials can be used to effectively meet the intent of the standard.	Any direction provided outside of Appendix 3a of the Rules of Procedure (i.e., the Standards Process Manual, including the Process for Developing a Term and/or the Process for Developing an Interpretation), would be arbitrary and unsupported by anything directly written or reasonably implied in the Standard.
Effective Date	NERC needs to incorporate a reasonable implementation period for all CANs.	There must be adequate time to allow them to prepare and submit the TFEs, and for the Regional Entities to evaluate them.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Compliance Application Notice — 0031

CIP-006 R1 Acceptable Opening Dimensions

DRAFT

Posted [DATE]

Primary Interest Groups
Compliance Enforcement Authority (CEA)[1]
NERC
Regional Entity
Registered Entities subject to CIP-005 and CIP-006
Responsible Entities[2]

Issue: What is the acceptable unprotected opening dimension in the Physical Security Perimeter (PSP)?
For the purpose of aiding a CEA, this CAN provides instruction to assess whether an opening in the PSP must have additional protective measures in place.

Background
CIP-006 R1.1 is intended to ensure protection of assets within an ESP via a "six-wall" border or documented alternative measures. To date there are a variety of ways in which entities have endeavored to create a completely enclosed (six-wall) border.

Compliance Application
CIP-006 states, in pertinent part:

> ***R1.*** *Physical Security Plan – The Responsible Entity shall document, implement, and maintain a physical security plan, approved by the senior manager or delegate(s) that shall address, at a minimum, the following:*
>
> > ***R1.1.*** *All Cyber Assets within an Electronic Security Perimeter shall reside within an identified Physical Security Perimeter. Where a completely enclosed ("six-wall") border*

[1] Compliance Enforcement Authorities include ERO auditors, investigators, enforcement personnel or any person authorized to assess issues of concern, potential non-compliance, and possible, alleged or confirmed violations of NERC Reliability Standard requirements.
[2] Within the text of Standard CIP-006, "Responsible Entity" shall mean: Reliability Coordinator; Balancing Authority; Interchange Authority; Transmission Service Provider; Transmission Owner; Transmission Operator; Generator Owner; Generator Operator; Load Serving Entity; NERC; and Regional Entity

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

cannot be established, the Responsible Entity shall deploy and document alternative measures to control physical access to such Cyber Assets.

R.1.2. *Identification of all physical access points through each Physical Security Perimeter and measures to control entry at those access points.*

R.1.3. *Processes, tools, and procedures to monitor physical access to the perimeter(s).*

CEAs are to consider 96 square inches as the measurement for each maximum acceptable opening without physical protective measures in place. This is consistent with other agencies that use similar measurement practices in other industries.

- Director of Central Intelligence Directive (DCID) 6/9 is the Manual of Physical Security Standards for Sensitive Compartmented Information Facilities (SCIF) adopted by the Department of Defense (DOD). Section 3.3.4 of this document references the 96-square-inch metric in regard to physical protection of vents, ducts and pipes. http://www.fas.org/irp/offdocs/dcid6-9.pdf

- Department of Homeland Security Management Directives System MD# 11030.1 is the Manual of Physical Protection of Facilities and Real Property adopted by the Department of Homeland Security (DHS). Section VI.A.2 of this document references a 100-square-inch metric in regard to areas of single openings for perimeter walls. http://www.dhs.gov/xlibrary/assets/foia/mgmt_directive_110301_physical_protection_of_facilities_and_real_property.pdf

- DOD Directive 5210.63 is the directive for Security of Nuclear Reactors and Special Nuclear Materials. In Enclosure 2 of this directive, definition E2.1.16.2 references 96 square inches as the maximum allowable opening without protective measures for Special Nuclear Material Vaults. http://biotech.law.lsu.edu/blaw/dodd/corres/pdf2/D521063p.pdf

Additionally, for any opening greater than 96 square inches with one side greater than 6 inches in length, CEAs are to look for evidence that the opening is protected against entry by the use of bars, wire mesh or other permanently installed metal barrier that leaves no opening greater than 6 inches on its shortest side.

Several application examples include:

- An opening of 8 inches by 8 inches would not require any additional protection since the opening is less than 96 square inches.
- An opening of 2 inches by 100 inches would not require any additional protection, because even though the opening is greater than 96 square inches, the smaller dimension is less than 6 inches.
- An opening of 8 inches by 15 inches would require metal bars or mesh since the opening is greater than 96 square inches, and the smaller dimension is greater than 6 inches.
- An opening of 8 inches by 100 inches that cannot be closed in by bars or mesh due to safety/regulatory requirements but upon which entities utilized “alternative measures”

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

(e.g., electronic sensors) would require a TFE to be filed with the appropriate Regional Entity.

Effective Period for CAN

This CAN is effective upon posting as final on the NERC Web site, and is to be used by CEAs to assess compliance from the posting date forward, regardless of the start date of any non-compliance or Possible Violation. It supersedes all prior communications and will remain in effect until such time that a future version of a FERC-approved or other applicable government authority-approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN.

For any enforcement action in process and for audits that have been initiated,[3] a CEA will apply the appropriate discretion, including consideration of the specific facts and circumstances of the non-compliance, in determining whether to assess compliance pursuant to this CAN.

Evidence of Compliance

A CEA is to assess the following to obtain reasonable assurance of the entity's compliance:

- That any opening that does not have physical protective measures in place is less than 96 square inches.

- That any opening greater than 96 square inches, with its shortest side greater than 6 inches in length, is protected against entry by the use of bars, wire mesh or other permanently installed metal barrier that leaves no opening greater than 6 inches on its shortest side.

  In addition, a CEA is to verify that a responsible entity submitted a TFE for CIP-006 R1.1 that outlines the basis and alternate and/or compensating measures for any opening over 96 square inches without physical protective measures. For example, a motion detector is a non-physical protective measure.

For more information please contact:

Michael Moon
Director of Compliance Operations
michael.moon@nerc.net
404-446-2567

Valerie Agnew
Manager of Interface and Outreach
valerie.agnew@nerc.net
404-446-2566

Ben Engelby
Senior Compliance Interface and Outreach Specialist
ben.engelby@nerc.net
404-446-2578

[3] "Initiated" means that a registered entity has received notification of the upcoming audit.

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

This document is designed to convey compliance monitoring instruction to achieve a measure of consistency among auditors and Compliance Enforcement Authorities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing NERC Reliability Standard. Compliance will continue to be assessed based on language in the currently enforceable NERC Reliability Standards. This document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement, or foreclose a registered entity's demonstration by alternative means that it has complied with the language and intent of the standard or requirement, taking into account the facts and circumstances of a particular registered entity. Implementation of information in this document is not a substitute for compliance with requirements in NERC's Reliability Standards.

3353 Peachtree Road NE
Suite 600 North Tower
Atlanta, GA 30326
404.446.2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0031 Comment Analysis Summary

CIP-006 R1 Acceptable Opening Dimensions

CAN-0031 provides instruction for a CEA to assess whether an opening in the Physical Security Perimeter (PSP) must have additional protective measures in place. The CAN incorporates the direction provided by the NERC Board of Trustees in August of 2011.

The draft CAN was posted for industry comment on the NERC web site on September 23, 2011, and the comment period expired on October 14, 2011. NERC received approximately 17 comments from registered entities and three comments from trade associations, which are identified below. The main themes of the comments consisted of the following three categories: errata changes, scope and effective date of the CAN.

Errata

The recommended errata change was to remove references to CIP-005 in the applicability section of the CAN, which was done. There was a change made with regard to the length of "any side greater than 6 inches" to now read "its shortest side greater than 6 inches." Also, in the evidence of compliance section, the word "preventative" was added with a footnote to clarify that physical preventative measures are needed, not physical detection controls (also discussed below).

Scope

There were several recommended substantive changes to the CAN in regard to scope. The commenters stated that CAN-0031 goes beyond the requirements in the standards, and Compliance Enforcement Authority (CEA) staff should not be instructed to verify evidence of 96 inches, because the standard does not articulate an exact measurement.

In response to the comments, CAN-0031 was drafted to ensure consistency among the ERO. Because the language of the standard does not state a number as an acceptable opening, the standard could be applied inconsistently. In order for Compliance Enforcement Authority (CEA) staff to assess compliance in a consistent manner, 96 square inches was determined to be appropriate, because it is consistent with other agencies, including the Department of Defense and the Department of Homeland Security.

Some commenters suggested that the CAN be further expanded to include other examples of different shapes, such as a circle or a polygon. In response, the shape of the opening is not the subject of the discussion, and calculations may need to be made in order to determine if an opening is greater than 96 square inches.

Other comments discussed the material used to enclose those openings and suggested to include other materials beside metal. In response, the language was changed from metal to "other permanently installed barrier," and a footnote was added to clarify that true physical prevention control, rather than physical detection control (such as motion sensors), is the goal of installing these barriers.

Effective Date

Several commenters believe that NERC should incorporate a reasonable implementation period with adequate time to allow registered entities to prepare and submit the Technical Feasibility Exceptions (TFEs), and for the Regional Entities to evaluate them. CEAs will apply discretion in applying the compliance application for registered entities that have had an audit initiated. Entities are encouraged to assess their facilities and to submit TFEs to their applicable Regional Entity if necessary.

Conclusion

The analysis spreadsheet for CAN-0031 and the industry comments that were received have been posted on the NERC website in addition to this Comment Analysis Summary. NERC received feedback that the spreadsheet format did not provide sufficient information to provide industry with visibility into the effort that is put into reviewing all of the comments. In order to provide increased transparency to the comment analysis phase of the CAN process, the industry comments are being posted, and this document has been created to supplement the information contained in the spreadsheet.

NERC staff thanks industry members for the time and effort put into providing the comments and feedback for CAN-0031. If you would like further discussion on CAN-0031, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
Associated Electric Cooperative, Inc., Basin Electric Power Cooperative, Inc., and Tri-State Generation and Transmission Association, Inc. (G&T Cooperatives)
Arizona Public Service (AZPS)
Bonneville Power Administration (BPA)
Dominion Resources Services, Inc.
Florida Municipal Power Agency (FMPA)
Kansas City Power and Light (KCP&L)
Madison Gas and Electric Company
MidAmerican Energy Company
PacifiCorp
Pepco Holdings, Inc.

Progress Energy (PGN)
Southern Company
Westar Energy
Xcel Energy

Trade Associations that submitted CAN Comments
Edison Electric Institute (EEI)
ISO/RTO Council Standards Review Committee (IRC SRC)
National Rural Electric Cooperative Association (NRECA)

Industry Comments for CAN-0030

Comment Topics	Main Points	Industry Suggestions
Supports CAN	Supports the changes made since the last draft of this CAN, including removal of: 1) the notarization requirement, and 2) the requirement to document a person's actual knowledge of an event that did not occur.	Attestations represent a reasonable means for an appropriate level of personnel of the registered entity to affirm its compliance with a standard. We thank NERC for removing the need for notarization from attestations.
Errata	Minor changes recommeded to CAN	The issue will read more precisely if the word “requirement” is added to the end. Compliance evidence resides at the requirement level.
Scope	Attestations are generally necessary when other evidence is unavailable, we do not agree that it is typically a result of some situation where documentation could have or should have been developed. Specifically, we believe this lack of documentation is often situationally based as a result of the reliability standard requirements.	A CEA should look for corroborating evidence if and only if the CEA has some reason to believe the person or entity has intentionally misrepresented the facts in their attestation.
Effective Date	NERC needs to incorporate a reasonable implementation period for all CANs.	Entities are not afforded any ability to adjust their programs, policies, systems or hardware to conform to these newly defined or clarified requirements.
Evidence	NERC should only verify attestations and should not look for additional corroborating evidence.	We suggest that NERC only direct CEA to conduct an investigation when other evidence supports a reasonable suspicion of a possible compliance violation.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN-0030 Comment Analysis Summary

Attestations

CAN-0030 provides instruction for assessing the appropriate uses of attestations as evidence of compliance with a reliability standard. The CAN was posted for industry comment on the NERC web site on October 19, 2011 and the comment period expired on November 9, 2011. NERC received 17 comments from registered entities and 3 comments from trade associations, which are identified below. The main themes of the comments consisted of the following four categories: errata changes, scope, effective date and evidence of compliance. In addition, there were a few comments that expressed appreciation for the removal of the notary requirement from previous version of the CAN.

Errata

The recommended errata change was implemented in order to clarify the issue statement by adding the word "requirement" to the end of the sentence.

Scope

There were several recommended substantive changes to the CAN in regard to scope.

A commenter stated that there first sentence of the Compliance Application section was inconsistent with the remainder of the CAN. The sentence states, "A CEA [compliance enforcement authority] is not to accept an attestation as a substitute for the registered entity's obligation to have maintained adequate records." The commenter believed that the first sentence contradicted the following instructions of the CAN, because there may be other instances beyond the three examples where the CEA may use discretion to allow an attestation.

In response to the comment, there is an obligation for registered entities to maintain records of compliance and have the evidence available during an audit; an attestation is not be an acceptable alternative to providing evidence. However there are times when an attestation is appropriate, and this CAN provides guidance to CEAs for three acceptable situations where an attestation is a sufficient form of evidence plus allows discretion in other circumstances not outlined in the CAN. The language in the CAN states "If no corroborating evidence is available, CEAs are not precluded from accepting an attestation but must evaluate the facts and circumstances to determine whether the attestation by itself constitutes sufficient evidence."

Another comment was made in reference to the second example in the Compliance Application section, which instructs CEAs to verify other corroborating evidence if the registered entity attests that an event did not occur. The commenter went on to state that corroborating attestations with supporting evidence for an event or situation did not occur will create unnecessary administrative burdens for both Registered Entities and Regional Entities.

In response to the comment, it is the CEA's duty to assess the evidence and to determine if the attestation provides reasonable assurance of the entity's compliance. In the event that no corroborating evidence is unavailable, a CEA must evaluate the facts and circumstances to determine whether the attestation alone constitutes sufficient evidence.

Another comment was submitted about the third example in the Compliance Application section that references NERC Compliance Process Bulletin #2011-001, Data Retention. The commenter stated that record retention is not directly related to the purpose of the CAN. Since the data retention subject is already addressed in referenced in a NERC Bulletin, it shouldn't be necessary to duplicate the requirements in this CAN. It was suggested that this item be deleted.

In response, the Data Retention Bulletin was included to provide CEAs with another reference with regard to attestations during their compliance monitoring of registered entities. The reference of attestations in the Public Notice Bulletin also states that CEAs are to verify the attested statements and any applicable corroborating evidence, which is consistent with the instruction in CAN-0030.

Effective Date

Several commenters believe that NERC should to incorporate a reasonable implementation period for all CANs. Other commenters suggested that a CAN should become effective only after it is publicly posted by NERC as final and provides in that posting an implementation and effective date which cannot be earlier than the posted date. There has been confusion from the industry about the date stated in the Effective Period of CAN section, as it refers to the date of the previously posted version.

The effective date for CAN-0030 is date that the CAN is posted as final on the NERC web site, which is the date CEAs are to begin using the compliance application to assess compliance.

Evidence

Commenters had questions regarding the Evidence of Compliance section. Particularly, several industry members stated that NERC should only verify attestations and should not look for additional corroborating evidence. The commenters stated that CEAs should only conduct an investigation when other evidence supports a reasonable suspicion of a possible compliance violation.

To clarify CAN-0030, attestations will be considered as evidence when a registered entity wishes to provide such evidence of compliance. However, to obtain reasonable assurance of compliance, CEAs are to verify if there are any other types of corroborating evidence to substantiate the attestation. The types of evidence that may be reviewed are documents, log books and interviews with registered entity staff. The determination of whether the attestation is sufficient on its own will be dependent on the specific facts and circumstances of the situation. Attestations are a tool to assist CEAs and registered entities during an audit, but they should not be used as an alternative to maintaining adequate records.

Conclusion

The analysis spreadsheet for CAN-0030 is posted on the NERC website. Because the spreadsheet format may not provide sufficient visibility into the effort that NERC puts into reviewing all of the comments received with respect to this CAN, this document is intended to supplement that information. NERC staff thanks industry for the time and effort put into providing that feedback. If you would like further discussion on CAN-0030, please feel free to contact us at cancomments@nerc.net.

Registered Entities that submitted CAN Comments

ACES Power Marketing
American Electric Power (AEP)
American Transmission Company (ATC)
Associated Electric Cooperative, Basin Electric Power Cooperative and Tri-State Generation and Transmission Association (G&T Cooperatives)
Bonneville Power Administration (BPA)
Central Lincoln
Constellation Energy (CEG)
Farmington Electric Utility System (FEUS)
First Energy (FE)
Ingleside Cogeneration/Occidental
Kansas City Power & Light (KCP&L)
Manitoba Hydro
Oncor Electric Delivery Company
PSEG Services Corporation
Puget Sound Energy (PSE)
Southern Company
Westar Energy

Trade Associations that submitted CAN Comments

Edison Electric Institute (EEI)
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
National Rural Electric Cooperative Association (NRECA)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net. Due to the amount of comments NERC receives, we will not accept attachments or comments submitted in another format.

Commenter Information

Name: Patti Metro

Phone Number: (703) 907-5817

Email Address: patti.metro@nreca.coop

Entity (ies) Represented: NRECA

Region(s): Not Applicable

Primary Interest Groups

Do you disagree with the groups mentioned? ○ Yes or No ◉

If yes, explain why:

Issue

Do you disagree with the issue statement of the CAN? ○ Yes or No ◉

If yes, explain why:

Background

Do you disagree with the background statement of the CAN? ◯ Yes or No ◉

If yes, explain why:

Compliance Application

Do you disagree with the compliance application section of the CAN? ◯ Yes or No ◯

If yes, explain why:

NRECA believes that Attestations are a key element in providing compliance evidence. It appears that if an entity develops an attestation it is a “statement of fact” or would not be used as evidence. Because of this, NRECA appreciates that in Draft CAN-0030 NERC removed the unnecessary requirement that the attestation be “under oath” and “witnessed for authenticity by a notary public”.

NERC provides examples of when an attestation is acceptable, but in doing has caused confusion with the example provided in bullet 2. NRECA believes the the following language needs to be removed from bullet 2 "such as a blank log book, showing that no communication occurred". If an entity attests that there was no such communication as described in bullet 2, there would be no entry in the log book for the specified type of communication. In addition, it is highly unlikely that an entity would have a completely blank log-book, therefore, the guidance provided does not serve the purpose of the verification described. It is the attestation and/or a statement that an an entity received or issued said communication that verifies that no communication occurred.

Effective Period for CAN

Do you disagree with the effective period of the CAN? ◯ Yes or No ◉

If yes, explain why:

Evidence of Compliance

Do you disagree with the evidence of compliance mentioned in the CAN? ◯ Yes or No ◯

If yes, explain why:

NRECA suggest removing “all” in bullet 1. It is understood that every effort should be made to provide available data and it is not necessary to quantify by including “all”. In addition, the language in bullet 2 is confusing with a convolution of how to attest that an event “did not” occur with what to do if an event “did” occur. Specifically, the removal of bullet 2a would provide some clarity. The discussion of this recommendation is provided in the comments to the Compliance Application question.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Jason Marshall

Phone Number: (317) 344-7204

Email Address: jmarshall@acespower.com

Entity Represented: ACES Power Marketing, Big Rivers Electric Corporation, Wabash Valley Power Association, Arizona Electric Power Cooperative, Southwest Transmission Cooperative, East Kentucky Power Cooperative, Old Dominion Electric Cooperative, and North Carolina Electric Membership Corporation

Region: RFC, SERC, WECC, SPP, MRO, ERCOT

Primary Interest Groups

Are you suggesting a change to the groups mentioned? No
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? No
If yes, explain what change and why:

Background
Are you suggesting a change to the background statement of the CAN? No
If yes, explain what change and why:

Attestations represent a reasonable means for an appropriate level of personnel of the registered entity to affirm its compliance with a standard. We thank NERC for removing the need for notarization from attestations.

Compliance Application
Are you suggesting a change to the compliance application section of the CAN? No
If yes, explain what change and why:

Effective Period for CAN
Are you suggesting a change to the effective period of the CAN? No
If yes, explain what change and why:

Evidence of Compliance
Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes
If yes, explain what change and why:

We appreciate NERC's efforts to provide some additional direction regarding an attestation's appropriate use, documentation and additional supporting evidence; however, we believe there are two issues with the guidance provided in the CAN regarding evidence of compliance to support a position that an event did not occur.

First, in subsection 2.a, the CEA should only look at a reasonable time period such as one shift or a single day where an event supposedly occurred when reviewing log books or records for blank entries or lack of entries. As it is written now, the CEA could review the logbooks and records for the entire audit period to search for an event that supposedly occurred during a specific period of time. This needs to be narrowed down in scope.

Second, the CAN creates an implied requirement to have a procedure or process when no requirement exists within subsection 2.b. Consider EOP-004-1 R3 which requires an LSE to report events meeting certain thresholds. There is no requirement to have a procedure or process. There is a very good chance that an LSE will not experience any reportable event during the audit period. In effect, this CAN adds a requirement to EOP-004-1 to have a procedure or process that is not consistent with the Standards Development Process which is part of the NERC Rules of Procedure.

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Thad Ness

Phone Number: 614-716-2053

Email Address: tkness@aep.com

Entity Represented: American Electric Power (AEP)

Region: ERCOT, RFC, SPP

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes / **No**
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes / **No**
If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? Yes / **No**
If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? **Yes** / No
If yes, explain what change and why:

Recommend adding additional text to the first sentence in the Compliance Application section so that it reads "A CEA is not to accept an attestation as a substitute for the registered entity's obligation to have maintained adequate records***, if explicitly required by the standard***."

AEP suggests that the supporting evidence to prove a negative is overreaching. This is a considerable amount of information to review and provide to in order to prove a negative. An attestation should be sufficient on its own. Furthermore, if there is corroborating evidence there probably would not be a need for an attestation.

AEP suggests striking out the last sentence for item number 2.

Effective Period for CAN
Are you suggesting a change to the effective period of the CAN? Yes / **No**
If yes, explain what change and why:

Evidence of Compliance
Are you suggesting a change to the evidence of compliance mentioned in the CAN? **Yes** / No
If yes, explain what change and why:

The word "all" should be removed from item number 1.

For item number 2, AEP suggests that the supporting evidence to prove a negative is overreaching. This is a considerable amount of information to review and provide in order to prove a negative. An attestation should be sufficient on its own. Furthermore, if there is corroborating evidence there probably would not be a need for an attestation.

Item number 3 references that the "CEA is instructed to look for the type of evidence outlined in Bulletin #2011-001, Data Retention." However, the list of evidence types outlined in the bulletin is qualified by an "or" conjunction and one of the "or" statements is an attestation. Therefore, that bulletin leads us to believe that an attestation alone is sufficient.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
CAN Number (0030)

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Annie Lauterbach

Phone Number: 360-418-2734

Email Address: ajlauterbach.bpa.gov

Entity (ies) Represented: Bonneville Power Administration

Region(s): WECC

Submitting on behalf of the following subject matter experts (SME's):

- Jenifur Rancourt, BPA - FERC Compliance
- Ryan Sigurdson, BPA - General Council
- Erika Doot, BPA – Generation Support

BPA thanks you for the opportunity to comment on CAN-0030 Attestations.

BPA supports the changes made since the last draft of this CAN, including removal of: 1) the notarization requirement, and 2) the requirement to document a person's actual knowledge of an event that did not occur.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
CAN Number 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Andrew Z.Pusztai

Phone Number: 262-506-6913

Email Address: apusztai@atcllc.com

Entity (ies) Represented: American Transmission Company

Region(s): MRO, RFC

Primary Interest Groups
Do you disagree with the groups mentioned? No [Yes or No]
If yes, explain why:

Issue
Do you disagree with the issue statement of the CAN? No [Yes or No]
If yes, explain why:

Background
Do you disagree with the background statement of the CAN? No [Yes or No]
If yes, explain why:

Compliance Application
Do you disagree with the compliance application section of the CAN? No [Yes or No]
If yes, explain why:

Effective Period for CAN
Do you disagree with the effective period of the CAN? Yes [Yes or No]
If yes, explain why:

A reasonable implementation period should be provided to allow entities time to adjust their programs and policies to conform to the newly clarified requirements. For this CAN an implementation period of six months is recommended.

Evidence of Compliance
Do you disagree with the evidence of compliance mentioned in the CAN? Yes [Yes or No]

If yes, explain why:

Item 3 of this section addresses record retention which is not directly related to the purpose of the CAN. Since the data retention subject is already addressed in referenced NERC Compliance Process Bulletin #2011-001, Data Retention, it shouldn't be necessary to duplicate the requirements in this CAN. It is suggested that this item be deleted.

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Steve Alexanderson

Phone Number: 541-574-2064

Email Address: salexanderson@cencoast.com

Entity Represented: Central Lincoln

Region: WECC

Primary Interest Groups

Are you suggesting a change to the groups mentioned? No
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? No
If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? No

If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes

If yes, explain what change and why:

Please remove the parts relating to “corroborating evidence.” The background states “In certain situations where documentation is not available, attestations may be provided to CEAs to demonstrate compliance.” Therefore, the possibility of corroborating documentation has already been ruled out, leaving an entity in a paradoxical situation: No corroborating documentation is available, so we must prepare an attestation and provide corroborating documentation to go along with it.

Effective Period for CAN
Are you suggesting a change to the effective period of the CAN? No
If yes, explain what change and why:

Evidence of Compliance
Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes
If yes, explain what change and why:

As stated above, the possibility of corroborating evidence has already been ruled out. The attestation itself should be enough. In addition, the requirement to provide logs and process documentation add requirements to standards that do not already have these requirements. IRO-001 R8/M7 for example, has no requirement for subject entities to maintain null logs of reliability directives or process documentation on how they are handled. Suggest removing 2a, 2b, and 2d.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
CAN Number 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Mark Gray

Phone Number: (202) 508-5122

Email Address: 701 Penn. Ave. NW, Washington DC 20004

Entity (ies) Represented: Edison Electric Institute and member companies

Region(s): All

CAN Topic: Attestations
Reliability Standard Referenced: None
Version of Reliability Standard: N/A
Requirements Referenced: None

General Comments

EEI respectfully submits that NERC continues to propose CANs that are, in fact, interpretations of approved Reliability Standard Requirements. Although CAN-0030 in our opinion does not contain any interpretations or new requirements, we do continue to see similar issues in other recently issued CANs. To this point, EEI notes that NERC expressly states that CANs do not and should not establish new requirements under the FERC-approved Reliability Standards and EEI urges NERC to hold to this basic policy principle. Furthermore, EEI suggests that NERC ought to reinforce to CEAs, as a routine part of their compliance guidance that CANs should not be considered as the sole method of attaining compliance. As is known, there is often more than one way for an entity to comply with a standard and in many cases requirements do not specifically define relevant terms or processes thereby allowing a broad range of solutions that an entity might achieve an equal level of compliance. To this point, we suggest that NERC's desire for more uniform enforcement must be tempered within the bounds of the plain language of the standard and we believe CEA should avoid the pitfalls of rigid compliance guidance which often lead to inadvertent interpretations.

EEI believes that prior to developing a CAN NERC should exercise more discernment when considering stakeholder questions and CAN candidate topics for CANs, and limit compliance direction to those questions that have clear merit.

We continue to believe that the CANs process would be better served by holding firm to the premise that CANs should be clear, concise and to the point; focused solely on clarifying the issue raised and strictly avoiding areas where no compliance concerns have been identified or raised.

Primary Interest Groups

Do you disagree with the groups mentioned? No [Yes or No]

Issue

Do you disagree with the issue statement of the CAN? Yes [Yes or No]

If yes, explain why: EEI generally agrees with the Issue statement as written but suggests the addition of the word "requirement" at the end of the second sentence since we believe the addition adds more specificity and accuracy to the statement.

Background

Do you disagree with the background statement of the CAN? Yes [Yes or No]

If yes, explain why: EEI suggests that the statement "An attestation is a written statement of fact, voluntarily made under an oath or affirmation and signed by the author." would be more accurately stated utilizing this or similar language:

> "An attestation is a written statement of fact, voluntarily made by a responsible individual, dully authorized by the responsible registered entity for whom the attestation is being made and provides necessary evidence that some action or act was conducted, as described within the attestation either by that person or as observed by that person. Additionally, the attestation is made valid by an affirming signature by the individual and dated. The attestation shall also include a statement indicating what action or act was performed as specified by the signature date or otherwise indicated in the attestation document or supporting documentation. In all cases, the person making the attestation must be appropriately qualified to either conduct the act or sufficiently knowledgeable to ensure that the act he/she witnessed was conducted to some reasonable standard."

Although EEI does agree attestations are generally necessary when other evidence is unavailable, we do not agree that it is typically a result of some situation where documentation could have or should have been developed. Specifically, we believe this lack of documentation is often situationally based as a result of the reliability standard requirements. For example, there are many requirements that obligate an entity to conduct a review of accounts, account privileges, events, etc.; however, in many if not most situations of this type an attestation that a review was conducted may be the only reasonable method for documenting the review was completed as required. Therefore, EEI submits that in these and many other similar situations an attestation, certifying that the review was conducted as required, is an effective compliance tool and does not signal any negligence on the part of an entity that is dutifully using such a tool.

Compliance Application

Do you disagree with the compliance application section of the CAN? Yes [Yes or No]

If yes, explain why: Although EEI agrees with the statement that an attestation should not be a substitute or in lieu of keeping adequate records; we do support and believe they are appropriate and effective when used correctly. We further believe that they add significant value in those situations where no other reasonable evidence or documentation could be developed or kept. For example, in CIP-008-3, Requirement R1.3 it states that "The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary." EEI submits that if no cyber security incident occurred during a given period no evidence would be available to demonstrate compliance, however, an attestation by the person responsible for tracking and reporting such incidents would be an effective method to comply with the requirement and provide necessary evidence to an auditor confirming entity compliance.

EEI has concerns that statements such as made in example 2 diminish the value of an attestation providing inappropriate compliance guidance suggesting that "a CEA is to look for evidence such as a blank log book, showing that no communication occurred, and/or statements from entities to support the entity's attestation". We believe this guidance is inappropriate and diminished the integrity of the person and entity making the attestation through unfounded mistrust. EEI recommends that alternatively, a CEA should look for other supporting evidence if and only if the CEA has some reason to believe the person or entity has intentionally misrepresented the facts in their attestation. To this point, EEI firmly believes that within most utilities, an intentional falsification of company records is a terminating offense. For this reason we believe it is unlikely that events such as this would occur given these known repercussions as well as the level and professionalism of those typically signing compliance attestations.

Otherwise, EEI generally agrees with the three examples provided in the CANs, to the extent the suggested modifications to example 2 as suggested above are included and offer a fourth for consideration:

> CEA is instructed to accept an attestation used by an entity to document quarterly, annual or other period reviews of certain reliability standard requirements if no other method of documenting such a review is built into their processes or procedures.

EEI recommends that the statement that a CEA should accept an attestation that is required by a CAN or Bulletin be removed since both provide compliance guidance and are not mandatory. EEI also questions the inclusion of statements that attestations should be accepted by CEAs if required by reliability standard requirements since these obligations are fully understood by the industry. We therefore suggest these statements add no value to the CAN and should be removed.

Effective Period for CAN

Do you disagree with the effective period of the CAN? Yes [Yes or No]

If yes, explain why: EEI believes that NERC needs to incorporate a reasonable implementation period for all CANs. Generally, we have observed that CANs routinely apply either retroactive enforcement or enforcement from the point of "Final Posting", such in this CAN. In both cases, entities are not afforded any ability to adjust their programs, policies, systems or hardware to conform to these newly defined or clarified requirements. This approach, if left unchanged, will ensure that many, if not most, registered entities will be continually self reporting their potential non-compliance as a result of CANs. This situation is concerning and troubling particularly at a time when NERC is pursuing Find, Fix, Track and Report as a way to redirect compliance resources to those issues that pose the greatest risk to Bulk Power System reliability.

Evidence of Compliance

Do you disagree with the evidence of compliance mentioned in the CAN? Yes [Yes or No]

If yes, explain why: EEI suggests the following or similar language as an alternative to the compliance guidance provided:

CEAs are to evaluate whether attestations provided met one of the four identified and accepted situation (3 by NERC, 1 suggested by EEI) where an attestation is considered acceptable evidence. If the attestation falls outside those bounds, the CEA is to first evaluate whether the entity made the attestation in the normal exercise of its compliance responsibility and no other evidence could have been reasonably been retained or otherwise provided. Next they should evaluate whether the attestation was developed as part of their normal compliance processes or in response to an impending compliance audit. If through this process the CEA determines that the attestation was made appropriately through the above measures, no other evidence could have been reasonably retained and it did not neglect any reliability standard requirement, the attestation should be accepted.

In all situations where an attestation is to be accepted, the CEA is advised to:

1. Confirm that the attestation was made by a duly authorized representative of the entity, and
2. The person making the attestation had adequate knowledge to assess whether the action or act was performed in a satisfactory manner, and
3. The action or act that is being attested to is completely and accurately described along with any findings included (if appropriate); and
4. The document is appropriately signed and dated

EEI submits that the CEA should not as a first step assume that an entity or their representative is misrepresenting the facts and the CEA should not conduct an onsite investigation as suggested unless faced with reasonable cause for such an action. Therefore, we suggest that NERC only direct CEA to

conduct an investigation when other evidence supports a reasonable suspicion of a possible compliance violation.

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:	Maggy Powell
Phone Number:	(410) 470-3382
Email Address:	Margaret.Powell@constellation.com
Entity Represented:	Constellation Energy on behalf of Baltimore Gas & Electric, Constellation Power Source Generation, Constellation Energy Nuclear Group, Constellation Commodities Group, Constellation New Energy and Constellation Energy Control and Dispatch.
Region:	All eight NERC regions

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes / No
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes / No
If yes, explain what change and why:

The issue will read more precisely if the word "requirement" is added to the end. Compliance evidence resides at the requirement level.

Background

Are you suggesting a change to the background statement of the CAN? Yes / No
If yes, explain what change and why:

No change suggested, but a comment. Constellation appreciates removal of reference that notarization is required for attestation "authenticity". Notarization was not required in any standard language. It would have added significant burden to entities while adding no value to the process.

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes / No
If yes, explain what change and why:

While the revised language is not as restrictive as previously drafted, more redrafting needs to be done to emphasize that, in practice, attestations serve a valuable role in scenarios beyond the CAN's limited examples of situations in which attestations are acceptable. No limitations on the use of attestations are described in any standard language or in the NERC Rules of Procedure. NERC should revise CAN-0030 to make clear that the circumstances discussed in the CAN do not reflect the universe of situations in which an attestation may be appropriately used for compliance. In addition, the discussion of corroborating evidence is far too weighted. The revised CAN-0030 may suggest to auditors that an attestation without corroborating evidence is insufficient. (See below for more specific comments under Evidence of Compliance).

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes / No
If yes, explain what change and why:

The effective date presents some challenges. Use of the term "effective period" implies that there is a compliance obligation associated with the CANs when, in fact, the compliance obligation remains within the Reliability Standard language. In all cases, CANs should be forward looking from the time a CAN is posted as final and should not be applied retroactively to any circumstance. Moreover, the effective date language in these CAN revisions states:

> *"[The CAN] supersedes all prior communications and will remain in effect until such time that a future version of a FERC or other applicable government authority approved standard or interpretation becomes effective and addresses the specific issue contained in this CAN."*

This language is troubling given that the effective date authority is expressly provided for in the Reliability Standards. The proposed effective period in the CANs should not usurp this authority in any way.

Once a future version of the Standard in question is approved and effective, judgment on whether the future version addresses the specific issue in the CAN is irrelevant in light of new Standard language and questions must be considered in the context of the newly applicable Standard language. The phrase "and addresses the

specific issue contained in this CAN" should be stricken. (As a side note, the CAN Process language may need to address how final CANs are to be treated when further revised. When a once final CAN is selected for revision, it makes sense that it would be rescinded and replaced by the updated final CAN thus removing any standing of the former final CAN).

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes / No

If yes, explain what change and why:

- *The discussion around corroborating evidence is given far too much weight. An attestation is a valuable evidentiary tool because it provides a statement of proof, in particular when no other evidence exists. It is an evidentiary tool designed to stand on its own, and should not automatically require other evidence in order to validate the truth of the statement provided therein.*

- *Item 2(a) discusses a blank log as corroborating evidence. A blank book is not compelling evidence and does not add weight to the attestation This will, however, create a rather odd administrative burden for entities to maintain a blank log book for events that do not occur. Within the real time operations, this is problematic. The attestation letter should stand alone in demonstrating compliance.*

- *Further, Item 2(c) states that "**additional statements from other internal operating personnel or from other entities that have actual knowledge of the event**" may serve as corroborating evidence. As stated, this is contrary to an attestation, which already is a sworn statement taken to confirm the absence of any compliance documentation due to the absence of an event requiring documentation. As well, providing a statement from another person or entity would likely take the form of an attestation, which would then bring into question whether one attestation can be used to sufficiently support another attestation.*

- *Item 1 directs the CEA to find reasonable assurance of compliance by looking at "**all applicable records in a registered entity's possession".** Without understanding or limitation to what is meant by "applicable" records, this statement places an unreasonable burden on an entity's obligation for audit and potentially goes well beyond the scope of the compliance requirements.*

Other Comments:

- *Expansion of Standard Scope: Constellation has an on-going concern that CANs are serving as interpretations and too often go beyond the actual language in the FERC approved Reliability Standard language. Constellation understands and is committed to the pursuit of reliability. There is, however, a critical difference between reliability and demonstration of compliance. Once in the compliance enforcement space, audits are beholden to the actual language in the Standard. By no means does this mean that practices beyond the Standard language are not taking place. It means that the audit is confirming compliance to the requirements of the Standard. If a greater measure of reliability practices is desired by the regulator, then the FERC approved process to achieve such revisions is the Standard Development Process. NERC has a substantial voice in the development of standards in that NERC Staff plays an active role in standard drafting teams and NERC is afforded the same opportunity within the comment periods. The reality is that Standard language will evolve and the mechanism in place for such evolution is the Standard Development Process. Anecdotally, there is little controversy within drafting teams to revise Standard language to address gaps between the compliance requirements and reliable operational practice. NERC will be well served to embrace that interface as a way to resolve their differences with the Standard language.*

- *Bulk Electric System ("BES") versus Bulk Power System ("BPS"): It is not clear why NERC uses the term BPS as opposed to BES in the Revised CANs. The NERC Reliability Standards apply to the BES unless otherwise noted in the Applicability Section of a Standard. Moreover, there is no definition of BPS in the NERC Glossary of Terms. The use of BPS in the CANs unnecessarily complicates and confuses the purported guidance therein. Accordingly, the Revised CANs should be further improved such that they all consistently use the NERC defined term BES and remove all references to the BPS.*

- *Source of the Question: It has been suggested previously that identification of the source of an issue for which a CAN is drafted would strongly enhance the reader's comprehension of the issue at hand and understanding of NERC's rationale. Accordingly, we suggest that clarifying the root of the issue within the CAN (i.e., identifying the initiator of the question and the context or circumstances leading to the question) will only help us better understand NERC's rationale behind the guidance provided.*

- *Focus of Issue Statements: The CANs often appear to attempt to answer a broad set of concerns about a Standard that are not raised in the issue posted. In addition, not all CANs state a specific Standard, requirement, or most importantly a version number. While some issues may warrant a broader application, for the most part, the questions seem to be directed at a specific incident related to a specific Standard and requirement. The version number fundamentally defines which Standard and the associated language in question. To the extent that the CANs can be focused to address the specific circumstances at issue, they should. The CAN should answer the question as simply and specifically as possible. Further, as suggested previously, identification of the source of an issue for which a CAN is drafted would strongly enhance the reader's comprehension of the issue at hand and understanding of NERC's rationale. Accordingly, we suggest that clarifying the root of the issue within the CAN (i.e., identifying the initiator of the question and the context or circumstances leading to the question) will only help us better understand NERC's rationale behind the guidance provided.*

- *Front-end Evaluation of Issues: Among the list of CAN issues, a few suggest that a CAN may or may not have been necessary. Certainly an openness to hear and consider all issues of concern raised is important and valuable; however, it is reasonable that not all issues will warrant a CAN. In addition to the work associated with the CAN Process, when a more expeditious remedy may exist, the CAN route runs the risk of going beyond the presented issue and potentially creating unnecessary controversy around Standard language. The CAN Process should consider development of a front end evaluation for issues raised for CAN consideration.*

- *Disclaimer Language: On a positive note, we reiterate our support for the disclaimer language at the conclusion of the Revised CANs stating that CANs are "not intended to establish new requirements or to modify the requirements in any existing NERC Reliability Standard." Further, we find the statement, "[t]his document is not intended to define the exclusive method an entity must use to comply with a particular standard or requirement…," particularly important given that many of these Standards have been in place for years, and while the Standard language may be sufficiently clear to be enforced, there exist multiple legitimate ways for entities to understand and comply with such language. This disclaimer should be highlighted to auditors, and NERC should avoid contradicting the premise of the disclaimer in the substantive content of the CANs.*

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Linda Jacobson

Phone Number: 505-599-1163

Email Address: ljacobson@fmtn.org

Entity Represented: Farmington Electric Utility System

Region: WECC

Primary Interest Groups

Are you suggesting a change to the groups mentioned? **No**
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? **No**
If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? **No**
If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? **No**
If yes, explain what change and why:
*** General comment: The CAN references Bulletin #2011-001, Data Retention. Bulletin #2011-001 references NERC Appendix 4C section 3.1.4.2. NERC Appendix 4C section 3.1.4.2 is under proposed revision. The footnote in Bulletin #2011-001 will need to be revised if the proposed changes to Appendix 4C are approved.**

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? **No**
If yes, explain what change and why:

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? **Yes**

If yes, explain what change and why:

2 allows an attestation to support a position an event did not occur.

2c states, "Additional statements from other internal operating personnel or from other entities that have actual knowledge of the event." If the attestation is that an event did not occur, there would not be any knowledge of 'the event.' Revise the 2c to align with the previous statement; such as, additional statements from other internal operating personnel or from other entities that support the attestation.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Michael Gammon

Phone Number: 816-654-1327

Email Address: mike.gammon@kcpl.com

Entity Represented: Kansas City Power & Light

Region: SPP

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes / **No**
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes / **No**
If yes, explain what change and why:

Background
Are you suggesting a change to the background statement of the CAN? **Yes** / No
If yes, explain what change and why:

KCP&L agrees that attestations are a valid source of evidence to demonstrate compliance, specifically where requirements are event driven and there has been no such event. However, there is a difference between a legal affidavit and an attestation. Although both documents provide a written statement of fact affirmed by the author as representation of facts, the written guidance in the CAN may still lead to confusion as to the expectations of the CEA. Expectations related to the documents submitted (under oath, notarized, signed by author and company's responsible officer, etc.) should be clarified in order to ensure the guidance is effective.

Compliance Application
Are you suggesting a change to the compliance application section of the CAN? Yes / **No**
If yes, explain what change and why:

The CAN-0030 states that a "written attestation may be accepted as evidence of compliance, particularly if corroborating evidence is available". There is no need for an attestation when corroborating evidence is available as support of a demonstration of compliance.

Effective Period for CAN
Are you suggesting a change to the effective period of the CAN? Yes / **No**
If yes, explain what change and why:

Evidence of Compliance
Are you suggesting a change to the evidence of compliance mentioned in the CAN? **Yes** / No
If yes, explain what change and why:

CAN-0030 specifies in item 2b that a Registered Entity must document the process (es) used to demonstrate how an event or request would have been recorded. The measures in the Standards and/or Data Retention in the Standards already specify the kinds of recording mediums that may be used to demonstrate compliance. There are many mediums that are acceptable and several may be utilized. Given the specific guidance in the Standards, it is not necessary to place additional burdens on the Registered Entity in documenting the specific mediums that may be utilized in recording the many circumstances and events that the Standards encompass as CAN-0030 in item 2b suggests. We recommend removal of item 2b from CAN-0030.

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Michelle D'Antuono

Phone Number: 713-215-7064

Email Address: michelle_dantuono@oxy.com

Entity Represented: Ingleside Cogeneration, LP

Region: TRE

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes / No
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes / No
If yes, explain what change and why:

Ingleside Cogeneration believes that the CAN is addressing a valid weakness in the proper application of attestations. It is not clear in the text of most measures when an attestation is an acceptable means to demonstrate compliance to the corresponding requirement – and what supplementary evidence is expected to be produced at an audit, if any.

Background

Are you suggesting a change to the background statement of the CAN? Yes / No
If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes / No
If yes, explain what change and why:

Ingleside Cogeneration acknowledges that three improvements have been made to the previous version of CAN-0030. First, the unnecessary requirement that all attestations be notarized has been removed. Secondly, the new draft clearly addresses a situation where corroborating evidence is not available or simply not needed – allowing the auditor to use sound judgment based upon the circumstances. Third, the specific examples provided by the drafting team are helpful.

However, Example 2 still calls for the Registered Entity to provide corroborating evidence when an event did not take place – such as a documented process which shows the actions to take should one occur or blank pages in operations logs. In our opinion, this does not sufficiently address the case where an external entity has not requested information or actions of the entity-under-review during the compliance time frame (e.g.; request for Facility Ratings Methodology). These requests do not necessarily route to an operations team - but may go to an Engineering organization in a less structured manner (email or unmonitored phone request).

Although Ingleside Cogeneration is committed to supporting all applicable reliability requirements, it seems unnecessary to develop formal processes for every possible request that could come to our facility. Instead, the audit team should either approach a potential requesting entity for examples of requests made, or confirmation that none occurred. Otherwise, they should be prepared to accept a stand-alone attestation as is.

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes / No
If yes, explain what change and why:

Ingleside Cogeneration LP believes that all CANs are insufficiently vetted through the stakeholder review process. Although we understand the need to clarify ambiguous language in the reliability requirements, the unintended consequences of what seems to be a reasoned result cannot be understated. NERC needs to commit that a resolution will be aggressively pursued through the Standards Development Process so that CANs are retired as rapidly as they have appeared.

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? Yes / No
If yes, explain what change and why:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Sam Ciccone

Phone Number: 330-252-6383

Email Address: sciccone@firstenergycorp.com

Entity Represented: FirstEnergy Corp.

Region: RFC

Primary Interest Groups

Are you suggesting a change to the groups mentioned? Yes / **No**
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? Yes / **No**
If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? Yes / **No**
If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? **Yes** / No
If yes, explain what change and why:

We do not agree with the following statement in #2:

"In order to support the entity's position that it did not receive any communication that would require performance, a CEA is to look for evidence such as a blank log book, showing that no communication occurred, and/or statements from entities to support the entity's attestation."

First, a blank log book in our opinion proves nothing and is an unreasonable method of proving an event did not occur. This is essentially requiring an entity to "prove the negative" so to speak. Requiring an entity to show something did not occur by providing, for example, a blank log book, seems unnecessary

and overly burdensome. Simple statement on RSAWs such as “we did not have this event” or” we did not receive this request” coupled with a letter signed by a designated company representative should suffice in these situations.

Second, what is the point of asking for statements from entities to support the entity’s attestation? Isn’t the attestation the statement the CEA needs?

Therefore, we suggest removing this sentence and that #2 should simply state: “2. CEAs are instructed to accept attestations in support of an entity’s position that an event or situation did not occur. An example of this scenario is if an entity is to perform a duty upon receiving communication.”

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? Yes / **No**

If yes, explain what change and why:

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? **Yes** / No

If yes, explain what change and why:

Similar to our previous comment, we suggest the removal of part ‘a’ in #2 which states: “Log books or records (either hardcopy or electronic) that show a blank entry or lack of an entry,”

General comment on proving an event did not occur:

Also, with respect to requirements such as those that compel an entity to respond to another entity’s request for information, and no information was requested, the CEA should accept an attestation in all cases. If the CEA decides it needs corroborating evidence, that CEA should make note of this in his audit report and confirm that no request for information was indeed made when an audit of the requesting entity is performed. For example, if the Transmission Owner (TO) is to provide the Planning Coordinator (PC) with information when requested, and the TO provides an attestation that they did not receive a request for information, this attestation should be sufficient. Then, if the CEA wants corroborating evidence, it should note this for the next audit, or a request for information, to the PC corroborating that they never asked for information from the TO.

Hello,

Manitoba Hydro would like to submit the following comments on Draft CAN-0030 "Attestations":

On Page 2 bullet 2c, it is unclear how staff can have" knowledge of an event" if the Registered Entity contends that an event did not occur?

Regards,

_____
Kasia Mihalchuk, P. Eng.
Manitoba Hydro

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net. Due to the amount of comments NERC receives, we will not accept attachments or comments submitted in another format.

Commenter Information

Name: Darryl Curtis

Phone Number: (214) 743-6827

Email Address: Darryl.Curtis@Oncor.com

Entity (ies) Represented: Oncor Electric Delivery Company LLC

Region(s): Texas RE

Primary Interest Groups

Do you disagree with the groups mentioned? ○ Yes or No ◉

If yes, explain why:

Issue

Do you disagree with the issue statement of the CAN? ○ Yes or No ◉

If yes, explain why:

Background

Do you disagree with the background statement of the CAN? ◯ Yes or No ◉

If yes, explain why:

Compliance Application

Do you disagree with the compliance application section of the CAN? ◯ Yes or No ◯

If yes, explain why:

Effective Period for CAN

Do you disagree with the effective period of the CAN? ◯ Yes or No ◉

If yes, explain why:

Evidence of Compliance

Do you disagree with the evidence of compliance mentioned in the CAN? ◯ Yes or No ◯

If yes, explain why:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Gary Kruempel- MidAmerican Energy Company

Phone Number: 515-281-2510

Email Address: gekruempel@midamerican.com

Entity Represented: MRO NSRF represented by: Madison Gas and Electric Company, Alliant Energy, Western Area Power Administration, Great River Energy, Xcel Energy, Rochester Public Utilities, Basin Electric Power Cooperative, Lincoln Electric System, American transmission Company, Wisconsin Public Service, Omaha Public Power District, Minnkota Power Cooperative, Midwest ISO, Otter Tail Power Company, Muscatine Power and Water, Nebraska Public Power District

Region: MRO

Primary Interest Groups

Are you suggesting a change to the groups mentioned? **No**

If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? **No**

If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? **No**

If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? **YES**
If yes, explain what change and why:

The first sentence of the Compliance Application section states *"A CEA is not to accept an attestation as a substitute for the registered entity's obligation to have maintained adequate records"* but the remainder of the section goes on to explain when attestations are acceptable. This sentence could be confusing and it is suggested that it be deleted. The remainder of the section explains when attestations can be acceptable and that should provide adequate guidance.

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? **YES**
If yes, explain what change and why:

A reasonable implementation period should be provided to allow entities time to adjust their programs and policies to conform to the newly clarified requirements. For this CAN, an implementation period of six months is recommended.

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? **YES**
If yes, explain what change and why:

Item 3 of this section does not appear to be relevant to the subject of the CAN. Since the data retention issue is addressed in the referenced bulletin it shouldn't need to be repeated in this CAN. It is suggested that this item be deleted.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
CAN Number 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: John Seelke

Phone Number: 973-430-5360

Email Address: john.seelke@pseg.com

Entity (ies) Represented: GO, GOP, LSE, PSE, TO

Region(s): RFC and NPCC

Primary Interest Groups

Do you disagree with the groups mentioned? Yes Yes or No

If yes, explain why: Suggest changing "Registered Entity" to "All Registered Entities" for "Each Registered Entity" if that's what's intended.

Issue

Do you disagree with the issue statement of the CAN? No Yes or No

If yes, explain why:

Background

Do you disagree with the background statement of the CAN? No Yes or No

If yes, explain why:

Compliance Application

Do you disagree with the compliance application section of the CAN? Yes Yes or No

If yes, explain why:

Item 2 states in part "In order to support the entity's position that it did not receive any communication that would require performance, a CEA is to look for evidence such as a blank log book, showing that no communication occurred, and/or statements from entities to support the entity's attestation." We do not believe a "blank log book" will demonstrate anything. Perhaps NERC meant to say "such as a log book demonstrating that no communication requiring performance was recorded." In addition, the correct and acceptable verification of an attestation regarding that no communication occurred requiring performance

would be to verify that with the reliability entity (e.g. TOP, BA, RC, etc.) who would have issued the communication.

When an event did not occur, there is no evidence regarding its non-occurrence. Events specified in standards (such as FAC-003-0) are recorded. If no events occurred, every non-occurrence was not recorded, and looking for such evidence is an unreasonable expectation. Except for communications, an attestation should be accepted without any corroboration regarding an event did not occur.

Effective Period for CAN

Do you disagree with the effective period of the CAN? No Yes or No

If yes, explain why:

Evidence of Compliance

Do you disagree with the evidence of compliance mentioned in the CAN? Yes Yes or No

If yes, explain why: We have issues with item 2a, 2b, and 2c, and have provided comments following each item:

2. To support a position that an event did not occur, a CEA is to look for:

   a. Log books or records (either hardcopy or electronic) that show a blank entry or lack of an entry,

      Strike the phrase "a blank entry or" since it is nonsensical as discussed in our comments on the Compliance Application section.

   b. A documented process to demonstrate how an event or request would have been recorded,

      Unless a given standard requirement (not "measure") specifies that an entity "have a plan" or that a given process or procedure be documented (e.g.FAC-008, EOP-005), this statement is an unwarranted and non-FERC-approved extension of the requirement. It also sets an unreasonable precedent and accepted practice for NERC and RE audit/ enforcement behaviors potentially applicable to a host of other things. While it is undoubtedly good utility and organizational practice to document practices and procedures the lack of same should not and cannot be grounds for a reliability standards violation.

      We suggest the CAN statement be modified by inserting "if having such process is a standard requirement" at the end of the sentence.

   c. Additional statements from other internal operating personnel or from other entities that have actual knowledge of the event, or

      Per our comments about the Compliance Application section above, we agree with this statement, and we suggest it be moved to the top of the list here and also be added to the Compliance Application statement.

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name:	Pamela Hunter
Phone Number:	(205) 257-7626
Email Address:	prhunter@southernco.com
Entity Represented:	Southern Company
Region:	SERC, FRCC, TRE, WECC

Primary Interest Groups

Are you suggesting a change to the groups mentioned? **No**
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? **No**
If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? **No**
If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? **No**
If yes, explain what change and why:

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? **No**

If yes, explain what change and why:

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? **Yes**

If yes, explain what change and why:

Recommend clarifying Item 2 in the section on Evidence of Compliance on p. 2 of 4 to add the word "or" after each of the items labeled a. through c. It is believed "or" is implied, but, in this case, "or" should be explicit. Note the addition of the word "or" in red font color in the draft below:

DRAFT:

2. To support a position that an event did not occur, a CEA is to look for:
    a. Log books or records (either hardcopy or electronic) that show a blank entry or lack of an entry, **or**
    b. A documented process to demonstrate how an event or request would have been recorded, **or**
    c. Additional statements from other internal operating personnel or from other entities that have actual knowledge of the event, or
    d. Other corroborating evidence to show that an event did not occur.

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net.

Commenter Information

Name: Beth Robinweiler

Phone Number: 425-457-5843

Email Address: beth.robinweiler@pse.com

Entity Represented: Puget Sound Energy

Region: WECC

Primary Interest Groups

Are you suggesting a change to the groups mentioned? No
If yes, explain what change and why:

Issue

Are you suggesting a change to the issue statement of the CAN? No
If yes, explain what change and why:

Background

Are you suggesting a change to the background statement of the CAN? No
If yes, explain what change and why:

Compliance Application

Are you suggesting a change to the compliance application section of the CAN? Yes
If yes, explain what change and why:

The first sentence contradicts the remainder of this section. As suggested in the remainder of the CAN,, there may be other instances beyond the three examples where the CEA may use discretion to allow an attestation. For example, there may be an instance where 1 or 2 records are missing (from a population of thousands), but there is some other kind of evidence to suggest that the proper activities were performed. While this should not be a recommended as a best practice, this discretion should reside with the CEA to make the determination if an attestation would suffice. Another example where an attestation may be appropriate is to support a verbal conversation. Therefore, please consider changing

the first sentence to: "A CEA should generally not accept an attestation as a substitute…" in order for the CEA to still retain that discretion.

Effective Period for CAN

Are you suggesting a change to the effective period of the CAN? No
If yes, explain what change and why:

Evidence of Compliance

Are you suggesting a change to the evidence of compliance mentioned in the CAN? No
If yes, explain what change and why:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CAN Comment Form
Compliance Application Notice – 0030

Please complete the CAN Comment Form and email it to cancomments@nerc.net. Due to the amount of comments NERC receives, we will not accept attachments or comments submitted in another format.

Commenter Information

Name: Bo Jones

Phone Number: (785) 575-1680

Email Address: Bo.Jones@westarenergy.com

Entity (ies) Represented: Westar Energy

Region(s): SPP

Primary Interest Groups

Do you disagree with the groups mentioned? ○ Yes or No ◉

If yes, explain why:

Issue

Do you disagree with the issue statement of the CAN? ○ Yes or No ◉

If yes, explain why:

Background

Do you disagree with the background statement of the CAN? ○ Yes or No ◉

If yes, explain why:

Compliance Application

Do you disagree with the compliance application section of the CAN? ◉ Yes or No ○

If yes, explain why:

CAN-0020 attempts to define the term "planned". The CAN process should not be used to define NERC terms. While we understand the need to provide guidance on the term "planned", we believe the Standard Development Process is the appropriate regulatory process to define terms.

The CAN references "outage schedules". It is not clear what is meant by "outage schedules" and therefore may result in inconsistent application of the CAN. We also believe that the use of this new term expands the scope of the Standard since the existing Standard does not specifically require outage schedules as compliance evidence.

In the "Outages to be included in TOP evaluations" section, the CAN states "TOP incorporated all maintenance outages - including short duration Protection system outages". 'Short duration' is vague and therefore will result in inconsistent application of the CAN.

Effective Period for CAN

Do you disagree with the effective period of the CAN? ◯ Yes or No ◉

If yes, explain why:

Evidence of Compliance

Do you disagree with the evidence of compliance mentioned in the CAN? ◯ Yes or No ◉

If yes, explain why:

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Announcement - "NEW" Weekly Standards Bulletin | November 7-13, 2011
Date: Monday, November 07, 2011 3:47:00 PM

Standards Bulletin: November 7-13, 2011

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and CANs posted for comment, industry review, or balloting, along with a list of upcoming standards-related postings and events. The bulletin is being piloted for the next few weeks, so any feedback on its effectiveness, content, and format is welcome. Please email Monica Benson with questions about standards commenting and balloting, Caroline Clouse with questions about CANs, and Mallory Huggins with feedback on this bulletin.

Now available on the Standards Under Development Page.

Proposed Standards and Interpretations Posted for Comment (comment periods close at 8 p.m. Eastern)

- Interpretation 2011-INT-01: Revision of MOD-028 to address RPL Request for Interpretation – Posted October 4 - November 16, 2011 (Comment Form)
- Project 2009-22: Interpretation of COM-002-2 R2 for IRC – Posted October 4 - November 17, 2011 (Comment Form)
- Regional Reliability Standard SERC RRSD Procedures – Posted October 4 - November 18, 2011 (Comment Form)
- Project 2010-07: Generator Requirements at the Transmission Interface (FAC-001-1, FAC-003-X, FAC-003-3, PRC-004-2) – Posted October 5 - November 18, 2011 (Comment Form)
- Project 2008-10: Revision of CIP-006-1 R1.1 to address Progress Energy Request for Interpretation – Posted October 12 - November 21, 2011 (Comment Form)
- Regional Reliability Standard VAR-001-2 WECC Variance – Posted October 20 - December 5, 2011 (Comment Form)

- Project 2007-12: Frequency Response (BAL-003-1) – Posted October 25 - December 8, 2011 (Comment Form)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Posted October 28 - December 12, 2011 (Comment Form)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Posted November 7, 2011 - January 6, 2012 (Comment Form)

Current Ballots for Proposed Standards or Interpretations (ballot periods close at 8 p.m. Eastern)

- Interpretation 2011-INT-01: Revision of MOD-028 to address FPL Request for Interpretation – Open November 7-16, 2011 (Initial Ballot)

- Project 2009-22: Interpretation of COM-002-2 R2 for IRC – Open November 8-17, 2011 (Initial Ballot)

- Project 2010-07: Generator Requirements at the Transmission Interface (FAC-001-1, FAC-003-X, FAC-003-3, PRC-004-2) – Open November 9-18, 2011 (Initial Ballot)

- Project 2008-10: Interpretation of CIP-006-1 R1.1 for Progress Energy – Open November 11-21, 2011 (Successive Ballot)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2008-10: Interpretation of CIP-006-1 R1.1 for Progress Energy – Open October 12 - November 10, 2011 (Join Ballot Pool)

- Project 2007-12: Frequency Response (BAL-003-1) – Open October 25 - November 23, 2011 (Join Ballot Pools – Initial Ballot and Non-Binding Poll)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open October 28 - November 28, 2011 (Join Ballot Pools – Initial Ballot and Non-Binding Poll)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Open November 7, 2011 - December 15, 2011 (Join Ballot Pool)

Pending Ballots for Proposed Standards or Interpretations (ballot periods close at 8

p.m. Eastern)

- Project 2007-12: Frequency Response (BAL-003-1) – Open November 30 - December 8, 2011 (Initial Ballot and Non-Binding Poll)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open December 2-12, 2011 (Initial Ballot and Non-Binding Poll)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Open December 16, 2011 - January 6, 2012 (Initial Ballots)

Compliance Application Notices (CANs) Posted for Industry Review

- Comments due by November 9, 2011 to cancomments@nerc.net using the CAN Comment Form:

  - CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages (Redline and Clean)

  - CAN-0030 Attestations (Redline and Clean)

- Comments due by November 23, 2011 to cancomments@nerc.net using the CAN Comment Form:

  - CAN-0040 BAL-004 Frequency Response Calculation (Clean Draft)

  - CAN-0043 PRC-005 Protection System Maintenance and Testing Evidence (Clean Draft)

Standard Drafting Team Vacancies

- Any industry stakeholder meeting the indicated qualifications for one of the following vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

  - Project 2007-06 System Protection Coordination: Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

  - Project 2007-12 Frequency Response: Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

- Project 2010-07 Generator Requirements at the Transmission Interface: Seeking an individual, preferably from a Regional Entity, with a compliance role or background. Candidate should have experience working with generation, transmission, or both. The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.

Upcoming Events

- Standards Committee Conference Call – November 10, 2011, 1-5 p.m. Eastern (Agenda)
- Compliance Workshop, Atlanta, GA – December 6, 2011, all day (Register)

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1275498-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - November 14-20, 2011
Date: Monday, November 14, 2011 9:43:43 AM

Standards Bulletin
November 14-20, 2011

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and CANs posted for comment, industry review, or ballot, along with a list of upcoming standards-related postings and events. The bulletin is being piloted for the next few weeks, so any feedback on its effectiveness, content, and format is welcome. Please email Monica Benson with questions about standards commenting and balloting, Caroline Clouse with questions about CANs, and Mallory Huggins with feedback on this bulletin.

Now available on the Standards Under Development page.

Current Ballots for Proposed Standards or Interpretations (ballot periods close at 8 p.m. Eastern)

- Interpretation 2011-INT-01: Revision of MOD-028 to address FPL Request for Interpretation – Open November 7-16, 2011 (Initial Ballot)

- Project 2009-22: Interpretation of COM-002-2 R2 for IRC – Open November 8-17, 2011 (Initial Ballot)

- Project 2010-07: Generator Requirements at the Transmission Interface (FAC-001-1, FAC-003-X, FAC-003-3, PRC-004-2) – Open November 9-18, 2011 (Initial Ballot)

- Project 2010-17: Definition of Bulk Electric System – Open November 10-21, 2011 (two Recirculation Ballots, one for the Definition of BES and one for *Detailed Information to Support an Exception Request* application form)

- Project 2008-10: Interpretation of CIP-006-1 R1.1 for Progress Energy – Open November 11-21, 2011 (Successive Ballot)

Proposed Standards and Interpretations Posted for Comment (comment periods

close at 8 p.m. Eastern)

- Interpretation 2011-INT-01: Revision of MOD-028 to address RPL Request for Interpretation – Posted October 4 - November 16, 2011 (Comment Form)

- Project 2009-22: Interpretation of COM-002-2 R2 for IRC – Posted October 4 - November 17, 2011 (Comment Form)

- Regional Reliability Standard SERC RRSD Procedures – Posted October 4 - November 18, 2011 (Comment Form)

- Project 2010-07: Generator Requirements at the Transmission Interface (FAC-001-1, FAC-003-X, FAC-003-3, PRC-004-2) – Posted October 5 - November 18, 2011 (Comment Form)

- Project 2008-10: Revision of CIP-006-1 R1.1 to address Progress Energy Request for Interpretation – Posted October 12 - November 21, 2011 (Comment Form)

- Regional Reliability Standard VAR-001-2 WECC Variance – Posted October 20 - December 5, 2011 (Comment Form)

- Project 2007-12: Frequency Response (BAL-003-1) – Posted October 25 - December 8, 2011 (Comment Form)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Posted October 28 - December 12, 2011 (Comment Form)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Posted November 7, 2011 - January 6, 2012 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2007-12: Frequency Response (BAL-003-1) – Open October 25 - November 23, 2011 (Join Ballot Pools – Initial Ballot and Non-Binding Poll)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open October 28 - November 28, 2011 (Join Ballot Pools – Initial Ballot and Non-Binding Poll)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Open November 7, 2011 - December 15, 2011 (Join Ballot Pool)

Pending Ballots for Proposed Standards or Interpretations (ballot periods close at 8 p.m. Eastern)

- Project 2007-12: Frequency Response (BAL-003-1) – Open November 30 - December 8, 2011 (Initial Ballot and Non-Binding Poll)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open December 2-12, 2011 (Initial Ballot and Non-Binding Poll)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Open December 16, 2011 - January 6, 2012 (Initial Ballots)

Compliance Application Notices (CANs) Posted for Industry Review

- Comments due by November 23, 2011 to cancomments@nerc.net using the CAN Comment Form:

  - CAN-0040 BAL-004 Frequency Response Calculation (Clean Draft)

  - CAN-0043 PRC-005 Protection System Maintenance and Testing Evidence (Clean Draft)

Proposed Changes to the NERC Rules of Procedure and Associated Appendices Posted for Comment

- Comments on changes to Sections 100-1600 and associated Appendices 4B, 4C, 5A, and 8 and deletion of Appendices 3C and 6 are posted on NERC's Rules of Procedure webpage – Due by December 22, 2011 to ROPcomments@nerc.net

Standard Drafting Team Vacancies

- Any industry stakeholder meeting the indicated qualifications for one of the following vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

  - Project 2007-06 System Protection Coordination: Seeking an individual from a

Canadian entity with experience in coordination of protection systems (new installations and revisions).

- Project 2007-12 Frequency Response: Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

Upcoming Events

- Industry Webinar: Project 2007-12 Frequency Response – November 14, 2011, 1-5 p.m. Eastern (Register)
- Industry Webinar: Project 2008-06 Cyber Security Order 706 – November 15, 2011, 1-3 p.m. Eastern (Register)
- Compliance Workshop, Atlanta, GA – December 6, 2011, all day (Register)

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You have received this email because you are a registered representative in the Registered Ballot Body.

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - November 21-27, 2011
Date: Monday, November 21, 2011 10:02:36 AM

Standards Bulletin
November 21-27, 2011

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and CANs posted for comment, industry review, or ballot, along with a list of upcoming standards-related postings and events. The bulletin is being piloted for the next few weeks, so any feedback on its effectiveness, content, and format is welcome. Please email Monica Benson with questions about standards commenting and balloting, Caroline Clouse with questions about CANs, and Mallory Huggins with feedback on this bulletin.

Now available on the Standards Under Development page.

STANDARDS ITEMS

Current Ballots for Proposed Standards or Interpretations (ballot periods close at 8 p.m. Eastern)

- Project 2010-17: Definition of Bulk Electric System – Open November 10-21, 2011 (two Recirculation Ballots, one for the Definition of BES and one for *Detailed Information to Support an Exception Request* application form)

- Project 2008-10: Interpretation of CIP-006-1 R1.1 for Progress Energy – Open November 11-21, 2011 (Successive Ballot)

Proposed Standards and Interpretations Posted for Comment (comment periods close at 8 p.m. Eastern)

- Project 2008-10: Revision of CIP-006-1 R1.1 to address Progress Energy Request for Interpretation – Posted October 12 - November 21, 2011 (Comment Form)

- Regional Reliability Standard VAR-001-2 WECC Variance – Posted October 20 - December 5, 2011 (Comment Form)

- Project 2007-12: Frequency Response (BAL-003-1) – Posted October 25 - December 8, 2011 (Comment Form)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Posted October 28 - December 12, 2011 (Comment Form)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Posted November 7, 2011 - January 6, 2012 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2007-12: Frequency Response (BAL-003-1) – Open October 25 - November 23, 2011 (Join Ballot Pools – Initial Ballot and Non-Binding Poll)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open October 28 - November 28, 2011 (Join Ballot Pools – Initial Ballot and Non-Binding Poll)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Open November 7, 2011 - December 15, 2011 (Join Ballot Pool)

Pending Ballots for Proposed Standards or Interpretations (ballot periods close at 8 p.m. Eastern)

- Project 2007-12: Frequency Response (BAL-003-1) – Open November 30 - December 8, 2011 (Initial Ballot and Non-Binding Poll)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open December 2-12, 2011 (Initial Ballot and Non-Binding Poll)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Open December 16, 2011 - January 6, 2012 (Initial Ballots)

Standard Drafting Team Vacancies

- Any industry stakeholder meeting the indicated qualifications for one of the following vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

    - Project 2007-06 System Protection Coordination: Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

    - Project 2007-12 Frequency Response: Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

OTHER ITEMS

Compliance Application Notices (CANs) Posted for Industry Review

- Comments due by November 23, 2011 to cancomments@nerc.net using the CAN Comment Form:

    - CAN-0040 BAL-004 Frequency Response Calculation (Clean Draft)

    - CAN-0043 PRC-005 Protection System Maintenance and Testing Evidence (Clean Draft)

Proposed Changes to the NERC Rules of Procedure and Associated Appendices Posted for Comment

- Comments on changes to Sections 100-1600 and associated Appendices 4B, 4C, 5A, and 8 and deletion of Appendices 3C and 6 are posted on NERC's Rules of Procedure webpage – Due by December 22, 2011 to ROPcomments@nerc.net

UPCOMING EVENTS

Compliance Workshop

2011 Compliance Workshop, Atlanta, GA – December 6, 2011, all day (Register)

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You have received this email because you are a registered representative in the Registered Ballot Body.

From: Monica Benson
To: monica.benson@nerc.net
Subject: NERC: Standards Bulletin - November 28-December 4, 2011
Date: Monday, November 28, 2011 10:16:07 AM

Standards Bulletin
November 28-December 4, 2011

This weekly bulletin compiles a list of current and upcoming standards, interpretations, and CANs posted for comment, industry review, or ballot, along with a list of upcoming standards-related postings and events. The bulletin is being piloted for the next few weeks, so any feedback on its effectiveness, content, and format is welcome. Please email Monica Benson with questions about standards commenting and balloting, Caroline Clouse with questions about CANs, and Mallory Huggins with feedback on this bulletin.

Now available on the Standards Under Development page.

STANDARDS ITEMS

Current Ballots for Proposed Standards or Interpretations (ballot periods close at 8 p.m. Eastern)

- Project 2007-12: Frequency Response (BAL-003-1) – Open November 30 - December 8, 2011 (Initial Ballot and Non-Binding Poll)

Proposed Standards and Interpretations Posted for Comment (comment periods close at 8 p.m. Eastern)

- Regional Reliability Standard VAR-001-2 WECC Variance – Posted October 20 - December 5, 2011 (Comment Form)

- Project 2007-12: Frequency Response (BAL-003-1) – Posted October 25 - December 8, 2011 (Comment Form)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Posted October 28 - December 12, 2011 (Comment Form)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Posted November 7, 2011 - January 6, 2012 (Comment Form)

Join Ballot Pools (ballot pool windows close at 8 a.m. Eastern)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Open November 7, 2011 - December 15, 2011 (Join Ballot Pool)

Pending Ballots for Proposed Standards or Interpretations (ballot periods close at 8 p.m. Eastern)

- Project 2009-01: Disturbance and Sabotage Reporting (EOP-004-2) – Open December 2-12, 2011 (Initial Ballot and Non-Binding Poll)

- Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) – Open December 16, 2011 - January 6, 2012 (Initial Ballots)

Standard Drafting Team Vacancies

- Any industry stakeholder meeting the indicated qualifications for one of the following vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

    - Project 2007-06 System Protection Coordination: Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

    - Project 2007-12 Frequency Response: Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

OTHER ITEMS

Compliance Application Notices (CANs) Posted for Industry Review

- Comments due by December 14, 2011 to cancomments@nerc.net using the CAN Comment Form:
    - CAN-0027 TOP-003 R2 Coordination of Scheduled Outages (Clean Draft)

Proposed Changes to the NERC Rules of Procedure and Associated Appendices Posted for Comment

- Comments on changes to Sections 100-1600 and associated Appendices 4B, 4C, 5A, and 8 and deletion of Appendices 3C and 6 are posted on NERC's Rules of Procedure webpage – Due by December 22, 2011 to ROPcomments@nerc.net

UPCOMING EVENTS

Compliance Workshop

2011 Compliance Workshop, Atlanta, GA – December 6, 2011, all day (Register)

Webinars

Project 2008-06: Cyber Security Order 706 (Version 5 CIP Standards) Webinar – November 29, 2011, 1:00-3:30 p.m. Eastern (Register)

For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You have received this email because you are a registered representative in the Registered Ballot Body.

From:	Guy V. Zito
To:	rsc
Cc:	UFLSSDT
Subject:	NPCC UFLS CEAP Report
Date:	Friday, November 04, 2011 8:06:21 AM
Attachments:	NPCC_CEAP_2011-GVZ_UFLS_11-4-11.doc
Importance:	High

RSC Members et al,

Attached please find our first NPCC Cost Effective Analysis Procedure "CEAP" Report for the NPCC UFLS Regional Standard. This report, as previously indicated, is developed by staff and based on the responses we received during the CEAP posting. We had a very good level of responses and also support for the standard. We will be posting this report, along with the standard and implementation plan during the ballot period.

In addition, Lee and I will be posting all the documents and procedures and processes we approved at the RSC meeting last week on the NPCC website. I want to thank you all for a very productive meeting last week.

I also will be sending out a list of the tentative RSC meeting dates we agreed to in Boston along with their venue soon. Please review the meeting dates for any potential conflicts with other meetings you may be attending and propose alternatives.

Thanks,

Guy V. Zito
Asst. Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Northeast Power Coordinating Council, Inc.
Cost Effectiveness Analysis Procedure "CEAP"

For

NPCC Regional Reliability Standard
Underfrequency Load Shedding
PRC-006-NPCC-01



The NPCC Regional Standards Committee
11/4/2011

I. EXECUTIVE SUMMARY

During a 2010 FERC technical conference, the Commission recognized that "reliability does not come without cost" and significant industry interest was expressed in the development of a process to identify costs for draft Reliability Standards including the ability of the proposed Standard to achieve their reliability objective(s) in an efficient and cost effective manner. Additionally, the NPCC Board of Directors (BOD) during its consideration of the Disturbance Monitoring Regional Standard, requested the development of a formal procedure to assess the implementation costs and the relevant incremental reliability improvement (benefits) that a Regional Standard would provide.

Accordingly, NPCC Staff has developed a Cost Effectiveness Analysis Procedure (CEAP) and applied it to the PRC-006-NPCC-01 draft UFLS Regional Standard to address these concerns. Since the effort to draft an UFLS Regional Standard and revise the performance attributes of the program was underway prior to the development of the CEAP, in some cases this report relies on prior estimates to demonstrate adherence to the principles set forth in the CEAP.

The CEAP introduces two assessments of the estimated implementation costs of the requirements in a proposed draft Standard which include a Cost Benefit Analysis "CBA" and the Cost Effectiveness Analysis "CEA". These assessments are being incorporated into the Standard's development process. The purpose of the CEAP , conducted in parallel with the drafting process, is designed to provide supporting information and background for NPCC stakeholders, ballot body and the NPCC Board of Directors without delaying the development of the Standard. The CEAP also provides a "snapshot" of the cost of a proposed Standard, while soliciting input from a wide range of industry viewpoints, including NPCC's technical groups in order to determine if there is an adverse impact to reliability or affects potential adherence to other NPCC Regional or Continent wide Standards or Criteria should the draft Standard be approved.

This CEAP for PRC-006-NPCC-1 was developed by compiling the responses to questions posted for industry comment and some prior cost assessments during the development of NPCC Directory #12.

The results of the CEAP have determined that in the view of most stakeholders, the standard satisfactorily achieves an adequate level of reliability, is cost effective in achieving the reliability objective, has no adverse impact on reliability and is not cost prohibitive. Therefore, the NPCC Regional Standards Committee (RSC) recommends stakeholder and BOD adoption of this Standard.

II. COST BENEFIT ANALYSIS (PHASE 1)

NPCC performed a *Cost Benefit Analysis (CBA)* that was based on a number of factors and was used in determining whether a Regional Standard should proceed to development. Prior to the development of PRC-006-NPCC, the NPCC region had a regional UFLS program in place along with criteria that its Members were required to adhere to. In 2006 the NPCC technical groups assessed the adequacy of the regional UFLS program to determine if reliability objectives continued to be met and published the results in the "*2006 Assessment of Under frequency Load Shedding Adequacy Part III – Assessment of Program Modifications and 2008 Assessment of Under frequency Load Shedding Adequacy – Québec Area*". This study was approved by the Reliability Coordinating Committee "RCC" on November 19, 2008 along with a set of recommendations and an implementation schedule to initiate and complete the required changes. The decision to change the performance characteristics of the UFLS program was based on the critical importance of UFLS to maintain system stability, reliability prevent cascading outages.

The attributes of the new UFLS program were subsequently incorporated into NPCC Directory #12 and approved by the NPCC Full Members on June 26, 2009. Directory #12 is the foundation document for the NPCC UFLS Regional Standard and the cost information available to RCC and NPCC Full Members at that time was contained in a survey analysis performed by the Task Force on System Protection (TFSP). The estimated total cost of the UFLS program change and implementation was estimated to be approximately **$ 8M** for the region. This estimate represented only the cost of those who responded and did not reflect the potential total cost of compliance to the criteria within the region.

The decision to develop the NPCC UFLS Standard was based on the significant reliability benefit and the relatively low cost of development. The standard fills a reliability related need and achieves an adequate level of reliability by arresting frequency decay and maintaining stable islands after potential breakup while mitigating the probability of a cascading widespread outage. In addition the standard was fully coordinated with the NERC UFLS Continent-Wide Standard and developed to "augment" and implement that standard.

Additionally, the Standard closes a significant reliability gap since it requires all applicable regional entities to adhere to the programs requirements, regardless of their membership status with NPCC and a Members obligation to adhere to the criteria. Mandatory requirements subject to enforcement through legislation will demonstrate the importance of UFLS.

Finally, the CEAP revealed that many of the entities required to make changes associated with the new UFLS program have cost recovery mechanisms in place.

III. COST EFFECTIVENESS (PHASE 2)

The *Cost Effectiveness Analysis (CEA)* was performed to provide information about the effectiveness and relative cost of the Standard's requirements to achieve the objective or reliability goal for which the Standard was written. This involved a set of questions soliciting industry feedback on the technical feasibility of achieving the reliability objective of the Standard via its requirements and to solicit information on implementation costs, cost recovery, procurement of any resources needed to demonstrate compliance with the draft Standard.

These questions were focused on the individual requirements of the standard and all cost information submitted by entities was reviewed and compiled by NPCC Staff prior to being made public and presented to the RSC.

Market issues of individual stakeholders could exist or be revealed through the responses to the CEAP questions, therefore the necessary confidentialities have been maintained and no market sensitive information is revealed.

As part of determining cost effectiveness, the following questions were posted for a 30 day comment period and industry response;

1) **On a requirement by requirement basis, are the Requirements effective in achieving the reliability objective of the Standard and if not, why?**

2) **Are there alternative ways to achieve the draft Standard's reliability objective? If so, what alternatives are there and which requirements would they replace? This must be supported by studies done or be demonstrable.**

3) **On a requirement by requirement basis, do the draft requirements in the Standard achieve or contribute to a level of reliability that is "adequate", i.e. acceptable? If so, how? If not, why not?**

4) **Is there any adverse impact to reliability or any other existing standard, NPCC Regional Criteria, or in-process project draft Standard(s), of which your organization is aware?**

5) **Describe the size of your organization in broad general terms, e.g. GO-Total installed MWs, TOs circuit miles by kV and total load served, etc.**

6) **What are the gross anticipated one-time and ongoing costs of implementing the Standard as presently drafted (labor and materials)? Is there a cost recovery mechanism in place for your organization, i.e. markets or tariffs?**

NPCC received responses from market participants consisting of large and small Transmission Owners, Reliability Coordinators, Generator Owners and a Consultant. The entities who responded, in a strong majority, indicated their support of the Standard and that its requirements are effective in achieving its reliability objectives.

One of the respondents had some specific suggestions regarding alternate requirements and revising the requirements. These same comments were also submitted during the Standards development when comments were solicited and were reviewed by the Standard Drafting Team (SDT) which provided respective responses to the comments at that time and additionally revised the standard's requirements to address the issue.

The majority of respondents indicated that the standard achieves an adequate level of reliability. Those who did not were mainly representatives of Generators Owners (GO) who remain opposed to securing compensatory load shedding when they are unable to comply with the Standard's thresholds for underfrequency trip protection on their generators. The SDT had also revised the language of two of the standard's requirements to address this issue however the responding GOs either did not review the revisions or still have an issue.

No existing or anticipated adverse reliability impact as a result of the Standard's implementation has been identified. There was concern expressed by one of the respondents that NERC Project 2007-09-Generator Performance is currently underway and that there may be some interaction with this standard. NPCC is aware of this concern and an NPCC representative is currently a member of the Project 2007-09 SDT and is actively coordinating within the SDT to make certain that no adverse impact with the NPCC Regional Standard exists. Furthermore a change to the performance curve in that continent wide standard is being proposed to coordinate with the Hydro Quebec UFLS program which will largely mitigate this issue.

All those who responded indicated implementation costs were minimal with the exception of the Generator Owners who were uncertain about costs and indicated that no direct recovery mechanism was available to them. Respondents that did submit cost estimates recognized that implementation of Directory #12 which outlines the same requirements as the Standard is already underway and those costs have already been agreed upon by NPCC's Full Members.

IV. CEAP RECOMMENDATION

This CEAP recommendation to accept the standard is based on the following:

- The CBA completed prior to the development of this Standard by the Task Force on System Protection (TFSP), estimated a relatively minimal cost of approximately $8 M for the NPCC Region. The CEA cost of implementing the Underfrequency load shedding improvements, was estimated to be $9.5 M and is an effective investment to maintain the continuity and reliability of the electric power system. The respondents expressed their opinions that there were no viable alternatives to the methods proposed in the Standard to achieve the desired reliability objectives.

- The NPCC Reliability Coordinating Committee approved technical studies performed by SS-38 for this UFLS program.

- CEA industry responses indicating a majority of respondents showing support for the standard including : no adverse reliability impacts, reasonable costs, achievement of an adequate reliability. The majority of respondents indicated the standard contained effective requirements to achieve the reliability objective.

- RCC approved implementation of Directory#12 *UFLS Program Requirements* which has identical program requirements and an implementation plan which is already underway,

- NPCC RSC and SDT recommendations in support of the Standard and its requirements which they have endorsed as efficiently and are critical in effectively achieving the reliability objective of the standard.

From:	Guy V. Zito
To:	rcc
Cc:	rsc
Subject:	IMPORTANT-Ballot for NPCC UFLS Regional Standard
Date:	Friday, November 11, 2011 7:36:07 AM
Importance:	High

Reliablity Coordinating Committee Members and Alternates,

The NPCC Regional Regional Reliability Standard for UFLS, PRC-006-NPCC-01 is currently posted for ballot through **11:59 pm, November 18, 2011**. Posted materials for your review include the standard(developed from the existing RCC approved Directory #12 UFLS), Implementation Plan(which was developed from the RCC implementation plan for Directory #12)), and a Cost Effectiveness Analysis Procedure report (developed from a previous TFSP report with additional information from a recent open posting). The proposed standard will have minimal impact to the region in regard to additional work or resources required to implement.

Please have your organization review the standards and posted materials at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=4

Please ensure your organization's representive reviews the materials and casts their vote accordingly. If you have any questions please contact me.

Thank-you,

Guy V. Zito
Assistant Vice President-Standards
Northeast Power Coordinating Council, Inc.
1040 Avenue of the Americas, 10 th Floor
New York, NY 10018
212-840-1070
212-302-2782 fax

From:	Gerard J. Dunbar
To:	general
Cc:	oeb; kal.ayoub@ferc.gov; howard.gugel@nerc.net
Subject:	Notice of 10 Day Ballot PRC-006-NPCC-01 UFLS
Date:	Monday, November 07, 2011 5:10:56 PM
Attachments:	PRC-006-NPCC-01 UFLS Transmittal 10 Day Ballot Nov 7 GJD.pdf



NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

November 7th, 2011

NPCC Full and General Members;

In accordance with the NPCC Regional Standard Development Procedure a notification of ballot has been posted for *NPCC Regional Standard PRC-006-1 Automatic Underfrequency Load Shedding* and its associated Implementation Plan.

The Task Force on System Studies (TFSS) and the Reliability Coordinating Committee (RCC) have each endorsed the draft of this standard and on September 30th, 2011 the NPCC Regional Standards Committee (RSC) authorized a 30 day pre-ballot review and subsequent 10 day ballot period.

Additionally, in response to a request from the NPCC BOD, NPCC has developed a Cost Effectiveness Analysis Procedure (CEAP) designed to assess the implementation costs and reliability benefit of this proposed standard. The results of that analysis have been summarized and included with the ballot materials.

Ballots may be cast effective immediately until the close of the ballot period at 2359 EST on November 18th, 2011.

The draft Standard, its Implementation Plan and the results of the Cost Effectiveness Analysis Procedure (CEAP) are posted on the NPCC Website and can be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=4

Please contact me with any questions regarding posted ballot materials, the NPCC Regional Standard Development Procedure or the Cost Effectiveness Analysis Procedure.

Respectfully,

Gerry Dunbar
Northeast Power Coordinating Council, Inc.
212.840.1070 (p)
212.302.2782 (f)
gdunbar@npcc.org

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

November 21st, 2011

NPCC Full and General Members;

In accordance with the NPCC Regional Standard Development Procedure the ballot period for NPCC Regional Standard *PRC -006-NPCC -01 Automatic Underfrequency Load Shedding* and its Implementation Plan closed at 2359 on November 18th, 2011.

The results of the ballot were as follows:

Quorum: 100% of Sectors participated.

Approval: 83.5%

A recommendation for final Regional approval will be sent to the NPCC Board of Directors for their consideration at their meeting on November 30th, 2011.

Contingent upon the approval of the NPCC BOD the Standard will be submitted to NERC for approval by the Board of Trustees with subsequent filings with the FERC and applicable provincial authorities thereafter.

Voting was conducted electronically and the full development record for the standard may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=4

Thank you for your participation.

Gerry Dunbar

Northeast Power Coordinating Council, Inc.

212.840.1070 (p)

gdunbar@npcc.org

cc:

NPCC Regional Standards Committee

Richard Burke Chairperson NPCC UFLS Regional Standard DT

Herb Schrayshuen –NERC Vice President Standards

Howard Gugel- NERC Manager Regional Standards

11/21/2011
11:35 AM

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 1, Transmission Owners	**19**	**17**	**0**		**14**	**2**	**1**
Bangor Hydro	1	1			1		
Central Hudson Gas and Electric Corporation	1	1			1		
Central Maine Power Company	1	1					1
Consolidated Edison Company of New York, Inc.	1	1			1		
Hydro One Inc	1	1			1		
Hydro-Quebec TransEnergie	1	1			1		
Long Island Power Authority	1	1				1	
National Grid	1	1			1		
New Brunswick Power Transmission Corporation	1	1			1		
New Hampshire Transmission, LCC	1	1				1	
New York Power Authority	1	1			1		
New York State Electric & Gas	1	1			1		
Northeast Utilities	1	1			1		
Nova Scotia Power Inc.	1						
NSTAR	1						
Orange & Rockland Utilities Inc	1	1			1		
Rochester Gas & Electric	1	1			1		
The United Illuminating Company	1	1			1		
Vermont Transco	1	1			1		

11/21/2011
11:35 AM

		1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 2, Reliability Coordinators	**5**	**5**	**0**		**5**	**0**	**0**
Hydro-Quebec TransEnergie	1	1			1		
Independent Electricity System Operator	1	1			1		
ISO-New England, Inc.	1	1			1		
New Brunswick System Operator	1	1			1		
New York Independent System Operator	1	1			1		

11/21/2011
11:35 AM

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 3, TDUs, Dist. And LSE	**19**	**12**	**0**		**11**	**1**	**0**
Braintree Electric	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Hingham Municipal Lighting	1						
Hydro One Inc	1						
Hydro Quebec Distribution	1	1			1		
Groton Electric	1	1			1		
Ipswich Municpal Light Department	1						
Long Island Power Authority	1	1				1	
Marblehead Municipal	1	1			1		
National Grid	1						
New York Power Authority	1	1			1		
Northeast Utilities	1	1			1		
Orange and Rockland Utilities Inc	1	1			1		
Princeton Municipal	1						
Shrewsbury	1	1			1		
Sterling Municpal Light Department	1						
Vermont Electric Cooperative, Inc.	1	1			1		
Wakefield Municipal Gas and Light Department	1	1			1		
Westfield Gas and Electric	1						

11/21/2011
11:35 AM

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 4, Generator Owners	**24**	**16**	**0**		**8**	**7**	**1**
AES	1	1				1	
Consolidated Edison Company of New York, Inc.	1	1			1		
Covanta	1						
Dominion Resources Inc.	1	1				1	
Dynergy	1	1			1		
Entergy Nuclear Northeast	1						
Exelon Generation	1	1			1		
Exeter Energy	1						
First Wind	1	1					1
International Power	1						
Long Island Power Authority	1	1				1	
Massachusettes Municipal	1						
New York Power Authority	1	1			1		
NextEra Energy Resources	1	1				1	
Northeast Utilities	1	1			1		
Nova Scotia Power Inc.	1						
NRG Energy	1						
Ontario Power Generation Inc.	1	1			1		
PSEG Power Connecticut	1	1				1	
PSEG Power NY	1	1				1	
Pur Energy	1						
Trans Canada	1	1			1		
US Power Generating	1	1				1	
Wheelabrator Westchester	1	1			1		

11/21/2011
11:35 AM

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 5, Marketers, Brokers, Aggragators	**15**	**12**	**0**		**4**	**4**	**4**
Brookfield Power Corporation	1						
Consolidated Edison Company of New York, Inc.	1	1			1		
Consolidated Edison Energy/Development	1	1			1		
Constellation Energy Commodities Group, Inc.	1	1			1		
H.Q. Energy Services (U.S.) Inc	1	1					1
HQ Energy Marketing, Inc.	1	1					1
Long Island Power Authority	1	1				1	
Massachusetts Municipal	1	1					1
Nalcor Energy	1	1					1
New York Power Authority	1	1			1		
PSEG Energy Resources	1	1				1	
PPL EnergyPlus, LLC	1	1				1	
Shell Energy North America	1						
Utility Services LLC	1	1				1	
Windy Bay Power	1						

11/21/2011
11:35 AM

NPCC Registered Members		1. Determine Quorum		2. Vote/Ballot Recording		
		In Attendance (denote w/ 1)	By Proxy (denote w/ 1)	Affirmative (denote w/ 1)	Negative (denote w/ 1)	Abstain (denote w/ 1)
Sector 6, Customers- large and small	**4**	**4**	**0**	**4**	**0**	**0**
Ascendant Energy Solutions, Inc.	1	1		1		
IBM	1	1		1		
Oxbow Sherman	1	1		1		
SGC Engineering	1	1		1		

11/21/2011
11:35 AM

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 7 State and Provincial Reg. and Govt. Authorities	**6**	**3**	**0**		**2**	**0**	**1**
Long Island Power Authority	1						
New York Power Authority	1	1			1		
Maine Public Utilities	1						
NH Public Utilities	1	1			1		
NYS Dept of Public Service	1	1					1
Vermont Department of Public Service	1						

11/21/2011
11:35 AM

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 8, Sub Regional Rel. Councils, REs and Others	**7**	**3**	**0**		**1**	**0**	**2**
New York State Reliability Council, LLC	1	1			1		
ERL Technologies	1	1					1
4G Technologies	1						
Mc Coy Power Consultants	1						
MRO	1						
PLM	1	1					1
VIASYN	1						

Determine Meeting Quorum

Sector	Sector Name	Total Registered	In Attendance	By Proxy	Total Represented	Sector % Attending	Sector Quorum
1	**Transmission Owners**	19	17	0	17	0.89	1
2	**Reliability Coordinators**	5	5	0	5	1.00	1
3	**TDUs, Dist. And LSE**	19	12	0	12	0.63	1
4	**Generator Owners**	24	16	0	16	0.67	1
5	**Marketers, Brokers, Aggragators**	15	12	0	12	0.80	1
6	**Customers- large and small**	4	4	0	4	1.00	1
7	**State and Provincial Reg. and Govt. Authorities**	6	3	0	3	0.50	1
8	**Sub Regional Rel. Councils, REs and Others**	7	3	0	3	0.43	0
		99	72	0	72		7

Quorum= 2/3 of the Members

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total Registered	Sector % Attending	Affirmative # of Votes	Affirmative Fraction	Negative # of Votes	Negative Fraction	Abstain # of Votes	Votes Cast Total (-Abstentions)	Sector has Voted(1-Y, 0-N)
1	**Transmission Owners**	19	0.89	14	0.875	2	0.125	1	16	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	19	0.63	11	0.917	1	0.083	0	12	1
4	**Generator Owners**	24	0.67	8	0.533	7	0.467	1	15	1
5	**Marketers, Brokers, Aggragators**	15	0.80	4	0.500	4	0.500	4	8	1
6	**Customers- large and small**	4	1.00	4	1.000	0	0.000	0	4	1
7	**State and Provincial Reg. and Govt. Authorities**	6	0.50	2	1.000	0	0.000	1	2	1
8	**Sub Regional Rel. Councils, REs and Others**	7	0.43	1	0.857	0	0.000	2	1	1
	Totals	99		49	6.682	14	1.175	9	63	8

Sum of Affirmative/Number of Sectors that Voted
MUST BE AT LEAST 0.67 to pass

0.835

Did MOTION PASS?

PASS

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

November 7th, 2011

NPCC Full and General Members;

In accordance with the NPCC Regional Standard Development Procedure a notification of ballot has been posted for NPCC Regional Standard PRC-006-1 *Automatic Underfrequency Load Shedding* and its associated Implementation Plan.

The Task Force on System Studies (TFSS) and the Reliability Coordinating Committee (RCC) have each endorsed the draft of this standard and on September 30th, 2011 the NPCC Regional Standards Committee (RSC) authorized a 30 day pre-ballot review and subsequent 10 day ballot period.

Additionally, in response to a request from the NPCC BOD, NPCC has developed a Cost Effectiveness Analysis Procedure (CEAP), designed to assess the implementation costs and reliability benefit of this proposed standard. The results of that analysis have been summarized and included with the ballot materials.

Ballots may be cast effective immediately until the close of the ballot period at 2359 EST on November 18th, 2011.

The draft Standard, its Implementation Plan, and the results of the Cost Effectiveness Analysis Procedure (CEAP) are posted on the NPCC Website and can be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=4

Please contact me with any questions regarding posted ballot materials, the NPCC Regional Standard Development Procedure or the Cost Effectiveness Analysis Procedure.

Respectfully,

Gerry Dunbar
Northeast Power Coordinating Council, Inc.
212.840.1070 (p)
212.302.2782 (f)
gdunbar@npcc.org

Standard Development Roadmap

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

Development Steps Completed:

1. NPCC Regional Standards Committee (RSC) authorized posting UFLS RSAR development on August 20, 2008.
2. UFLS RSAR posted on NPCC website on August 25, 2008.
3. NPCC Reliability Coordinating Committee (RCC) approved the Task Force on System Studies (TFSS) as the lead task force to initiate drafting a UFLS Regional Standards on September 4, 2008.
4. NPCC UFLS Regional Standard Drafting Team initial meeting on January 27, 2009.
5. First draft posted on the NPCC Website July 13, 2009 for a 45 day comment period.
6. Second draft posted on the NPCC Website May 26, 2010 for a 45 day comment period.
7. Third draft posted on the NPCC Website May 6, 2011 for a 45 day comment period.

Description of Current Draft:

This is the third draft of the proposed standard.

Future Development Plan:

Anticipated Action	Anticipated Date
1. Post the initial draft of the standard for 45 day comment period.	July 13, 2009 to August 27, 2009
2. Respond to comments on the first posting and post revised standard and implementation plan for a 45 day comment period.	September 2009 to May 2010 May 26, 2010 to July 9th, 2010
3. Respond to comments on the 2nd posting.	July 2010 to October 2010
4. Obtain RSC approval to move the standard forward to balloting.	November 2010
5. Post the standard and implementation plan for a 30 day pre ballot review.	December 2010

6. Conduct a ten day ballot.	December 2010
7. Respond to ballot comments and post revised standard and implementation plan for a 45 day comment period.	May, 2011.
8. Respond to comments on the 3rd posting.	July 2011
9. Obtain RSC approval to move the standard forward to balloting.	August 2011
10. Post the standard and implementation plan for a 30 day pre ballot review.	August 2011
11. Conduct a ten day ballot.	September 2011
12. Membership Approval.	September 2011.

Definitions of Terms Used in Standard

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

In the standards, defined terms are indicated with its first letter capitalized.

A. Introduction

1. Title: **Automatic Underfrequency Load Shedding**

2. Number: PRC-006-NPCC-1

3. Purpose: To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.

4. Applicability:

4.1. Generator Owner

4.2. Planning Coordinator

4.3. Distribution Provider

4.4. Transmission Owner

5. (Proposed) Effective Date: To be established.

B. Requirements

R1 Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R2 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3 Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]

R4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R5 Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

7.1 Eastern Interconnection – 100 ms

7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R11 Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

R12 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R14 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R15 Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.

20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

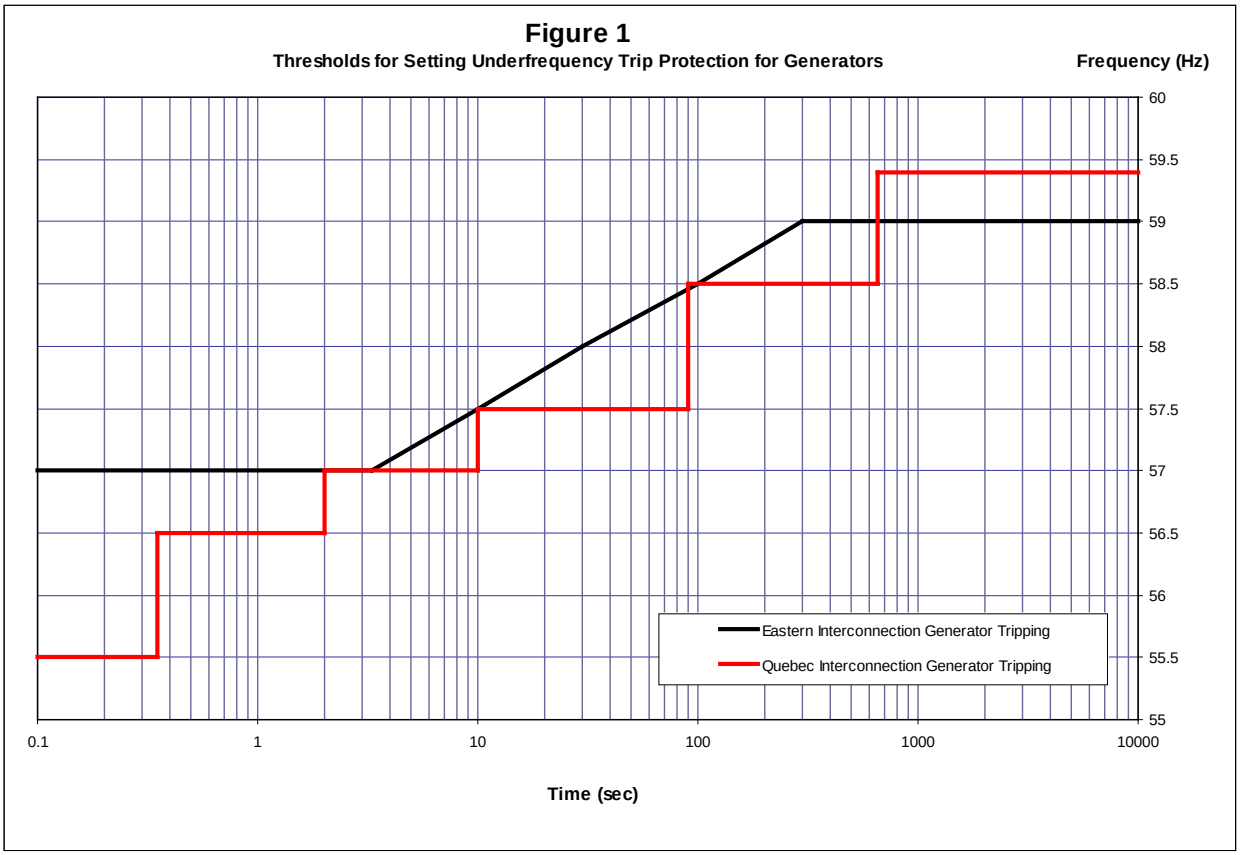
R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

Figure 1

Thresholds for Setting Underfrequency Trip Protection for Generators



C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested information.

R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		2 only, the need to deviate from providing two stages of UFLS.	Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	T	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8		N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12				The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted.

R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3.	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3.

R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times.)	Mvar at peak	Total Nominal Operating Time (s) [2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

Implementation Plan

Background:

The purpose of this draft Regional Standard is to ensure the development and maintenance of an effective and coordinated Automatic Underfrequency Load Shedding program in order to preserve the reliability and integrity of the bulk power system during declining system frequency events.

In the developing the Implementation Plan for PRC-006-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the UFLS program. The Regional Standard Drafting Team (RSDT) coordinated its development with the draft NERC UFLS Standard PRC-006. The intent of this Regional Standard is to be more stringent than the continent wide standard while incorporating specific program characteristics into the requirements.
2. The Implementation Plan for this standard is based, in part, on the timelines reflected in the existing and ongoing Implementation Plan for NPCC Directory #12 absent the annual milestones required by Directory #12.

Effective Dates:

Eastern Interconnection & Québec Interconnection Portions of NPCC Excluding the Independent Electricity System Operator (IESO) Planning Coordinator Area of NPCC in Ontario, Canada.

1. The effective date for requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than Jan 1, 2016 to allow for the existing implementation plan to be completed.

2. The effective date for requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

Independent Electricity System Operator (IESO) Planning Coordinator's Area of NPCC in Ontario, Canada

1. Effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

References:

- 2006 Assessment of UFLS Adequacy Part 3 Assessment of Program Modifications.
- SS38 Underfrequency Load Shedding Support Studies

NPCC Criteria:

- Directory #12 Underfrequency Load Shedding Program Requirements.
- A-7 NPCC Glossary of Terms.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Northeast Power Coordinating Council, Inc.
Cost Effectiveness Analysis Procedure "CEAP"

For

NPCC Regional Reliability Standard
Underfrequency Load Shedding
PRC-006-NPCC-01



The NPCC Regional Standards Committee
11/4/2011

I. EXECUTIVE SUMMARY

During a 2010 FERC technical conference, the Commission recognized that "reliability does not come without cost" and significant industry interest was expressed in the development of a process to identify costs for draft Reliability Standards including the ability of the proposed Standard to achieve their reliability objective(s) in an efficient and cost effective manner. Additionally, the NPCC Board of Directors (BOD) during its consideration of the Disturbance Monitoring Regional Standard, requested the development of a formal procedure to assess the implementation costs and the relevant incremental reliability improvement (benefits) that a Regional Standard would provide.

Accordingly, NPCC Staff has developed a Cost Effectiveness Analysis Procedure (CEAP) and applied it to the PRC-006-NPCC-01 draft UFLS Regional Standard to address these concerns. Since the effort to draft an UFLS Regional Standard and revise the performance attributes of the program was underway prior to the development of the CEAP, in some cases this report relies on prior estimates to demonstrate adherence to the principles set forth in the CEAP.

The CEAP introduces two assessments of the estimated implementation costs of the requirements in a proposed draft Standard which include a Cost Benefit Analysis "CBA" and the Cost Effectiveness Analysis "CEA". These assessments are being incorporated into the Standard's development process. The purpose of the CEAP, conducted in parallel with the drafting process, is designed to provide supporting information and background for NPCC stakeholders, ballot body and the NPCC Board of Directors without delaying the development of the Standard. The CEAP also provides a "snapshot" of the cost of a proposed Standard, while soliciting input from a wide range of industry viewpoints, including NPCC's technical groups in order to determine if there is an adverse impact to reliability or affects potential adherence to other NPCC Regional or Continent wide Standards or Criteria should the draft Standard be approved.

This CEAP for PRC-006-NPCC-1 was developed by compiling the responses to questions posted for industry comment and some prior cost assessments during the development of NPCC Directory #12.

The results of the CEAP have determined that in the view of most stakeholders, the standard satisfactorily achieves an adequate level of reliability, is cost effective in achieving the reliability objective, has no adverse impact on reliability and is not cost prohibitive. Therefore, the NPCC Regional Standards Committee (RSC) recommends stakeholder and BOD adoption of this Standard.

II. COST BENEFIT ANALYSIS (PHASE 1)

NPCC performed a *Cost Benefit Analysis (CBA)* that was based on a number of factors and was used in determining whether a Regional Standard should proceed to development. Prior to the development of PRC-006-NPCC, the NPCC region had a regional UFLS program in place along with criteria that its Members were required to adhere to. In 2006 the NPCC technical groups assessed the adequacy of the regional UFLS program to determine if reliability objectives continued to be met and published the results in the "*2006 Assessment of Under frequency Load Shedding Adequacy Part III – Assessment of Program Modifications and 2008 Assessment of Under frequency Load Shedding Adequacy – Québec Area*". This study was approved by the Reliability Coordinating Committee "RCC" on November 19, 2008 along with a set of recommendations and an implementation schedule to initiate and complete the required changes. The decision to change the performance characteristics of the UFLS program was based on the critical importance of UFLS to maintain system stability, reliability prevent cascading outages.

The attributes of the new UFLS program were subsequently incorporated into NPCC Directory #12 and approved by the NPCC Full Members on June 26, 2009. Directory #12 is the foundation document for the NPCC UFLS Regional Standard and the cost information available to RCC and NPCC Full Members at that time was contained in a survey analysis performed by the Task Force on System Protection (TFSP). The estimated total cost of the UFLS program change and implementation was estimated to be approximately **$ 8M** for the region. This estimate represented only the cost of those who responded and did not reflect the potential total cost of compliance to the criteria within the region.

The decision to develop the NPCC UFLS Standard was based on the significant reliability benefit and the relatively low cost of development. The standard fills a reliability related need and achieves an adequate level of reliability by arresting frequency decay and maintaining stable islands after potential breakup while mitigating the probability of a cascading widespread outage. In addition the standard was fully coordinated with the NERC UFLS Continent-Wide Standard and developed to "augment" and implement that standard.

Additionally, the Standard closes a significant reliability gap since it requires all applicable regional entities to adhere to the programs requirements, regardless of their membership status with NPCC and a Members obligation to adhere to the criteria. Mandatory requirements subject to enforcement through legislation will demonstrate the importance of UFLS.

Finally, the CEAP revealed that many of the entities required to make changes associated with the new UFLS program have cost recovery mechanisms in place.

III. COST EFFECTIVENESS (PHASE 2)

The *Cost Effectiveness Analysis (CEA)* was performed to provide information about the effectiveness and relative cost of the Standard's requirements to achieve the objective or reliability goal for which the Standard was written. This involved a set of questions soliciting industry feedback on the technical feasibility of achieving the reliability objective of the Standard via its requirements and to solicit information on implementation costs, cost recovery, procurement of any resources needed to demonstrate compliance with the draft Standard.

These questions were focused on the individual requirements of the standard and all cost information submitted by entities was reviewed and compiled by NPCC Staff prior to being made public and presented to the RSC.

Market issues of individuals takeholders could exist or be revealed through the responses to the CEAP questions, therefore the necessary confidentialities have been maintained and no market sensitive information is revealed.

As part of determining cost effectiveness, the following questions were posted for a 30 day comment period and industry response;

1) **On a requirement by requirement basis, are the Requirements effective in achieving the reliability objective of the Standard and if not, why?**

2) **Are there alternative ways to achieve the draft Standard's reliability objective? If so, what alternatives are there and which requirements would they replace? This must be supported by studies done or be demonstrable.**

3) **On a requirement by requirement basis, do the draft requirements in the Standard achieve or contribute to a level of reliability that is "adequate", i.e. acceptable? If so, how? If not, why not?**

4) **Is there any adverse impact to reliability or any other existing standard, NPCC Regional Criteria, or in-process project draft Standard(s), of which your organization is aware?**

5) **Describe the size of your organization in broad general terms, e.g. GO-Total installed MWs, TOs circuit miles by kV and total load served, etc.**

6) **What are the gross anticipated one-time and ongoing costs of implementing the Standard as presently drafted (labor and materials)? Is there a cost recovery mechanism in place for your organization, i.e. markets or tariffs?**

NPCC received responses from market participants consisting of large and small Transmission Owners, Reliability Coordinators, Generator Owners and a Consultant. The entities who responded, in a strong majority, indicated their support of the Standard and that its requirements are effective in achieving its reliability objectives.

One of the respondents had some specific suggestions regarding alternate requirements and revising the requirements. These same comments were also submitted during the Standards development when comments were solicited and were reviewed by the Standard Drafting Team (SDT) which provided respective responses to the comments at that time and additionally revised the standard's requirements to address the issue.

The majority of respondents indicated that the standard achieves an adequate level of reliability. Those who did not were mainly representatives of Generators Owners (GO) who remain opposed to securing compensatory load shedding when they are unable to comply with the Standard's thresholds for underfrequency trip protection on their generators. The SDT had also revised the language of two of the standard's requirements to address this issue however the responding GOs either did not review the revisions or still have an issue.

No existing or anticipated adverse reliability impact as a result of the Standard's implementation has been identified. There was concern expressed by one of the respondents that NERC Project 2007-09-Generator Performance is currently underway and that there may be some interaction with this standard. NPCC is aware of this concern and an NPCC representative is currently a member of the Project 2007-09 SDT and is actively coordinating within the SDT to make certain that no adverse impact with the NPCC Regional Standard exists. Furthermore a change to the performance curve in that continent wide standard is being proposed to coordinate with the Hydro Quebec UFLS program which will largely mitigate this issue.

All those who responded indicated implementation costs were minimal with the exception of the Generator Owners who were uncertain about costs and indicated that no direct recovery mechanism was available to them. Respondents that did submit cost estimates recognized that implementation of Directory #12 which outlines the same requirements as the Standard is already underway and those costs have already been agreed upon by NPCC's Full Members.

IV. CEAP RECOMMENDATION

This CEAP recommendation to accept the standard is based on the following:

- The CBA completed prior to the development of this Standard by the Task Force on System Protection (TFSP), estimated a relatively minimal cost of approximately $8 M for the NPCC Region. The CEA cost of implementing the Underfrequency load shedding improvements, was estimated to be $9.5 M and is an effective investment to maintain the continuity and reliability of the electric power system. The respondents expressed their opinions that there were no viable alternatives to the methods proposed in the Standard to achieve the desired reliability objectives.

- The NPCC Reliability Coordinating Committee approved technical studies performed by SS-38 for this UFLS program.

- CEA industry responses indicating a majority of respondents showing support for the standard including: no adverse reliability impacts, reasonable costs, achievement of an adequate reliability. The majority of respondents indicated the standard contained effective requirements to achieve the reliability objective.

- RCC approved implementation of Directory#12 *UFLS Program Requirements* which has identical program requirements and an implementation plan which is already underway,

- NPCC RSC and SDT recommendations in support of the Standard and its requirements which they have endorsed as efficiently and are critical in effectively achieving the reliability objective of the standard.



CONTENTS

BACKGROUND
Background information on this newsletter

DEADLINES
Deadlines for regional and NERC compliance related Filings

FERC
FERC Orders of Note and NERC Filings to FERC

NERC
NERC Standards Under Development, ballot results, and news

REGIONAL ENTITIES
News, ballot results, CMEP updates

NAESB
Subcommittee Information

COMPLIANCE CALENDAR
Upcoming meeting information for NERC and Regional Entities

Monthly NERC, NAESB, Regional Entity Update

Creating a Culture of Compliance

BACKGROUND

Outlined below is recent standards and compliance activity at NERC, NAESB and the Regional Entities. If you have comments for MISO consideration send them to standards&compliance@misoenergy.org

To facilitate communication regarding particular issues, two exploder lists have been created. The lists are titled, NERC_NAESB Monthly Update (join this list to receive this monthly report on NERC, NAESB, and Regional Activities), and Standards Collaboration (join this list to participate in meetings and receive communications on collaborating on comments to new and revised standards).

To join, please go to https://extranet.midwestiso.org. If you do not have an existing account, you will need to create one. Once you have created an account, click on "update account information," and check the box for the exploder/s you would like to join.

DEADLINES

NERC/NAESB/Regional Deadline Table		
Due Date	**Deliverable**	**Entity**
11/2/11	Close of Ballot Window for Project 2011-INT-01: Interpretation of MOD-028-1 for FPL	NERC
11/2/11	Close of Comment Period for PRC-006-RFC-01	RFC
11/3/11	Close of Ballot Pool for Project 2009-22: Interpretation of COM-002-2 for ISO/RTO Council	NERC
11/4/11	Close of Ballot Pool Formation for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
11/7/11	Opening of Initial Ballot Window for Project 2011-INT-01: Interpretation of MOD-028-1 for FPL	NERC
11/8/11	Opening of Initial Ballot Window for Project 2009-22: Interpretation of COM-002-2 for ISO/RTO Council	NERC
11/9/11	Opening of Initial Ballot Window for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
11/10/11	Close of Ballot Pool Formation for Project 2008-10: Interpretation of COP-006-x R1 for Progress Energy	NERC
11/11/11	Opening of Initial Ballot Window for Project 2008-10: Interpretation of COP-006-x R1 for Progress Energy	NERC
11/15/11	Data Submittal - BAL-001-0- Real Power Balancing Control Performance (CPS 1 & CPS 2): September, 2011	RFC
11/15/11	Data Submittal - BAL-006-1.1 - Inadvertent Interchange – September, 2010	RFC/ NERC
11/16/11	Close of Formal Comment Period for Project 2011-INT-01: Interpretation of MOD-028-1 for FPL	NERC
11/16/11	Close of Initial Ballot Window for Project 2011-INT-01: Interpretation of MOD-028-1 for FPL	NERC
11/17/11	Close of Formal Comment Period for Project 2009-22: Interpretation of COM-002-2 for ISO/RTO Council	NERC
11/17/11	Close of Initial Ballot Window for Project 2009-22: Interpretation of COM-002-2 for ISO/RTO Council	NERC
11/18/11	Close of Formal Comment Period for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
11/18/11	Close of Initial Ballot Window for Project 2010-07: Generator Requirements at the Transmission Interface	NERC
11/18/11	Close of Comment Period for SERC Regional Reliability Standards Development Procedure	NERC
11/21/11	Close of Formal Comment Period for Project 2008-10: Interpretation of COP-006-x R1 for Progress Energy	NERC
11/21/11	Close of Initial Ballot Window for Project 2008-10: Interpretation of COP-006-x R1 for Progress Energy	NERC
11/23/11	Close of Ballot Pool Window for Project 2007-12: Frequency Response	NERC
11/29/11	Opening of Initial Ballot and Non-Binding Poll Window for Project 2007-12: Frequency Response	NERC
12/5/11	Close of Comment Period for VAR-001-2 WECC Variance	NERC
12/8/11	Close of Formal Comment Period for Project 2007-12: Frequency Response	NERC
12/8/11	Close of Initial Ballot and Non-Binding Poll for Project 2007-12: Frequency Response	NERC

FERC

FERC Orders of Note

October 07, 2011

Order on Compliance Filing Regarding NERC's RoP, Pro Forma Delegation Agreements, and Delegation Agreements between FRCC and MRO Docket Nos. RR10-11-003, RR07-8-005, RR07-8-004, RR08-8-008, RR07-3-005, RR07-3-004, RR06-1-026, RR06-1-025, RR06-1-024

Notice of Technical Conference on Policy Issues Relating to the Reliability of the Bulk Power System Docket No AD12-1-000

Notice of Technical Discussion on Reliability Issues Relating to "Single Point of Failure on Protection Systems" Docket No. RM10-6-000

October 13, 2011

Notice and Request for Comment on Proposed Agency Information Collection Related to the Paperwork Reduction Act of 1995 and Proposed FAC-008-3 Standard Docket No. RD11-10-000

Letter Order Approving True-Up Filings for 2010 Budgets Docket No. RR11-4-000

October 17, 2011

Letter Order Accepting Amendments to Delegation Agreement Between NERC and NPCC and the NPCC RSDP Docket No. RR11-3-000

October 20, 2011

Order Accepting 2012 Business Plan and Budget of NERC Docket No. RR11-7-000

NOPR on Transmission Planning Reliability Standards TPL-002-0a Footnote "b" Docket No. RM11-18-000

Order Approving Interpretation of Reliability Standard TOP-002-2a Docket No. RD11-9-000

NOPR on Automatic UFLS and Load Shedding Plans Reliability Standards PRC-006-1 and EOP-003-2 Docket No. RM11-20-000

Order Denying Rehearing – US Army Corps – Tulsa District NOP Docket No. NP10-160-001

Order Approving Regional Reliability Standard PRC-002-NPCC-01 Docket No. RD11-8-000

October 27, 2011

Second Notice of Technical Conference on Penalty Guidelines Docket No. PL10-4-000

October 28, 2011

Order on Notices of Penalty – September 30, 2011 Notices of Penalty Docket Nos. NP11-267-000 – NP11-270-000

NERC Filings to FERC

October 03, 2011

Motion to Intervene and Comments Regarding City of Holland, Michigan Board of Public Works Docket No. RC11-5-000

October 19, 2011

Petition for Approval of a Revised Transmission Planning System Performance Requirements Reliability Standard TPL-001-2 and Five New Glossary Terms and for Retirement of Four Existing Reliability Standards Docket No. RM__-__-000

October 31, 2011

Informational Report of NERC on Analysis of Standards Process Results for the Third Quarter 2011 Docket Nos. RR06-1-000 and RR09-7-000

NERC

Standards Under Development

Click Picture for Link to NERC Reliability Standards Under Development Page

Reliability Standards Under Development			
Project	**Action**	**Start Date**	**End Date**
Current and Pending Ballots (Sorted by End Date)			
Interpretation 2011-INT-01 – Revision of MOD-028 to address FPL Request for Interpretation	Initial Ballot	11/07/11	11/16/11
Project 2009-22 – Interpretation of COM-002-2 R2 for IRC	Initial Ballot	11/08/11	11/17/11
Project 2010-07 – Generator Requirements at the Transmission Interface – FAC-001-1, FAC-003-X, FAC-003-3 and PRC-004-2.1	Initial Ballot	11/09/11	11/18/11
Project 2008-10 – Interpretation of CIP-006-1 R1.1 for Progress Energy	Successive Ballot	11/11/11	11/21/11
Project 2007-12 – Frequency Response	Initial Ballot and Non-Binding Poll	11/30/11	12/08/11
Project 2009-01 – Disturbance and Sabotage Reporting – CIP-001 and EOP-004	Initial Ballot and Non-Binding Poll	12/02/11	12/12/11
Join Ballot Pools (Ballot Pool Windows Close at 8 a.m. Eastern)			
Interpretation 2011-INT-01 – Revision of MOD-028 to address FPL Request for Interpretation	Join Ballot Pool	10/04/11	11/02/11
Project 2009-22 – Interpretation of COM-002-2 R2 for IRC	Join Ballot Pool	10/04/11	11/03/11
Project 2010-07 – Generator Requirements at the Transmission Interface – FAC-001-1, FAC-003-X, FAC-003-3 and PRC-004-2.1	Join Ballot Pool	10/05/11	11/04/11
Project 2008-10 – Interpretation of CIP-006-1 R1.1 for Progress Energy	Join Ballot Pool	10/12/11	11/10/11
Project 2007-12 – Frequency Response	Join Ballot Pools - Initial Ballot and Non-Binding Poll	10/25/11	11/23/11
Project 2009-01 – Disturbance and Sabotage Reporting – CIP-001 and EOP-004	Join Ballot Pools - Initial Ballot and Non-Binding Poll	10/28/11	11/28/11
Posted for Comment (Closes at 8 p.m. Eastern) (Sorted by End Date)			
Project 2010-17 – Definition of Bulk Electric System-Comment Period for Rules of Procedure Modifications to Support BES Exceptions	Comment Form	09/13/11	10/27/11
Regional Reliability Standard PRC-006-RFC-01	Comment Form	10/03/11	11/02/11
Interpretation 2011-INT-01 – Revision of MOD-028 to address FPL Request for Interpretation	Comment Form	10/04/11	11/16/11
Project 2009-22 – Interpretation of COM-002-2 R2 for IRC	Comment Form	10/04/11	11/17/11
Regional Reliability Standard SERC RRSD Procedures	Comment Form	10/04/11	11/18/11
Project 2010-07 – Generator Requirements at the Transmission Interface – FAC-001-1, FAC-003-X, FAC-003-3 and PRC-004-2.1	Comment Form	10/05/11	11/18/11
Project 2008-10 – Revision of CIP-006-1 R1.1 to address Progress Energy Request for Interpretation	Comment Form	10/12/11	11/21/11
Project 2007-12 – Frequency Response	Comment Form	10/25/11	12/08/11
Project 2009-01 – Disturbance and Sabotage Reporting – CIP-001 and EOP-004	Comment Form	10/28/11	12/12/11

NERC

Ballot Results

See more information on the NERC Ballot Results web page

Initial Ballot Results

- Project 2007-17: Protection System Maintenance and Testing

Voting statistics are listed below

Quorum: 84.86%

Approval: 61.10%

Non-Binding Poll Results for VRFs and VSLs

Quorum: 83.13%

Approval: 68.68%

The drafting team will consider all comments received, and decide whether to make additional revisions to the standards.

- Project 2010-17: Definition of Bulk Electric System

Voting statistics are listed below

BES Definition

Quorum: 92.97%

Approval: 71.68%

Technical Criteria to Support a BES Exception Request

Quorum: 89.53%

Approval: 764.03%

The drafting team will consider all comments received, and decide whether to make additional revisions to the definition of Bulk Electric System, the associated implementation plan, and the application form titled Detailed Information to Support an Exception Request referenced in the Rules of Procedure Exception Process. The drafting team is working to meet the regulatory deadline established in FERC Orders 743 and 743A (filing by January 25, 2012).

Recirculation Ballot Results

- Project 2007-07: Transmission Vegetation Management

Voting statistics are listed below

Quorum: 87.17%

Approval: 86.25%

The standard will be presented to the NERC Board of Trustees for adoption

Successive Ballot Results

- None

Final Ballot Results

- None

NERC Miscellaneous News

- The updated NERC CMEP can be found here.
- NERC is encouraging members to submit nominations for industry segment representatives on the Standard Committee (2012 – 2013 Term). The nomination form can be found here.
- Slides from the Reliability Standards and Compliance Workshop have been posted here.
- Two new lessons learned have been posted on the NERC website under "Events Analysis – Lessons Learned"
- The October 2011 NERC Newsletter can be found here.

REGIONAL ENTITIES

Reliability*First*

- The October RFC Newsletter can be found here.
- The presentations given at the 2011 Fall RFC Workshop have been posted for viewing here.
- RFC CMEP Update



2011 CIP Audit Schedule Rev. 13.xls



2011 RFC Compliance Monitoring Schedule

Midwest Reliability Organization (MRO)

- Find the September/October edition of the MRO Midwest Reliability Matters Newsletter Here.
- Find the MRO Standards page here.
- Find the MRO Compliance page here.

SERC

- See the latest SERC news here.
- Find the SERC Standards page here.

NAESB

NAESB Subcommittee Information

WEQ Business Practices Subcommittee (BPS)

- Information on the *Business Practices Subcommittee* is posted at: http://www.naesb.org/weq/weq_bps.asp

- The *Business Practices Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf3/weq_bps_exploder.pdf

WEQ OASIS Subcommittee:

- Information on the *OASIS Subcommittee* is posted at: http://www.naesb.org/weq/weq_oasis.asp

- The *OASIS Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_oasis_exploder.pdf

WEQ Joint Electric Scheduling Subcommittee (JESS):

- Information on the Joint Electric Scheduling Subcommittee is posted at: http://www.naesb.org/weq/weq_jess.asp

- The *Joint Electric Scheduling Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf4/weq_jess_exploder.pdf:

WEQ Standards Review Subcommittee (SRS):

- Information on the *Standards Review Subcommittee* is posted at: http://www.naesb.org/weq/weq_standards_review.asp

- The *Standards Review Subcommittee* has an exploder list which is used for the subcommittee to exchange information between meetings. To sign-up for this exploder list follow the instructions at: http://www.naesb.org/pdf3/weq_srs_exploder.pdf

COMPLIANCE CALENDAR

November 2011

Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
	1 RFC/OATI webCDMS webinar 2:00 – 3:00 PM	2	3 RFC/OATI webCDMS webinar 2:00 – 3:00 PM	4	5	6
7	8	9	10	11	12	13
14	15 NERC Webinar: Project 2008-06 Cyber Security Order 706 1:00 – 3:00 PM	16	17	18 NERC Webinar Establishing an Electronic Security Perimeter… 11:00 AM – 12:00 PM	19	20
21	22	23	24	25	26	27
28	29	30				

Future Meetings

- NERC
  - Dec 6, 2011: NERC Compliance Workshop, Atlanta, GA
  - For the complete NERC Meeting schedule, see: http://www.nerc.net/meetings/
- RFC
  - For the complete RFC Meeting schedule, see: https://www.rfirst.org/Pages/Calendar.aspx
- MRO
  - For the complete MRO Meeting schedule, see http://www.midwestreliability.org/meetings.html
- SERC
  - For the complete SERC Meeting schedule, see: http://www.serc1.org/Application/UpcomingMeetingsView.aspx

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC News

October 2011

Headlines

NERC General Counsel Announces Plans to Step Down from Duties in March; Search for Replacement Begins

Chief Security Officer Accepts Appointment to Department of Homeland Security

Compliance

Update on Compliance Application Notice Progress

Workshop News

2012 Audit Worksheets Posted

Critical Infrastructure

NERC Opened First Grid Security Conference in New Orleans

Reliability Assessments and Performance Analysis

NERC Launches Demand Response Availability Data System Website

Reliability Risk Management

Reliability Risk Management Group Formed

SAFNR V2 Project Updates Previous System

Standards

Nomination Time for Standards Committee

Addressing FERC Order 754

Update: 2012-2014 Reliability Standards Development Plan

Standard Drafting Team Vacancies

NERC Filings

Documents Filed with FERC and/or Canada During the Month

Careers

NERC Seeks Talented Professionals

Headlines

NERC General Counsel Announces Plans to Step Down from Duties in March; Search for Replacement Begins

David Cook, senior vice president and general counsel at the North American Electric Reliability Corporation, announced plans to step down from those duties on March 31.

Cook joined NERC in 1999, where he led NERC's efforts to secure passage of reliability legislation as part of the Energy Policy Act of 2005. Following passage of the legislation, Cook worked with industry stakeholders to gain certification of NERC as the "electric reliability organization" under the new section 215 of the Federal Power Act. As general counsel, he forged the rules and procedures for developing and enforcing mandatory reliability standards that are the core of this organization.

Prior to joining NERC, Cook spent 20 years with the Federal Energy Regulatory Commission, the last ten as deputy general counsel, where he was heavily involved in FERC's restructuring efforts for the natural gas and electric industries.

"David's contributions to NERC are numerous and have shaped the electric industry for many years, first at FERC and more recently at NERC. He has guided NERC's growth and development as the electric reliability organization with an unyielding commitment to an open, transparent stakeholder process," said Gerry Cauley, president and chief executive officer at NERC. "David's keen intellect, absolute integrity and careful legal scholarship have been a tremendous asset to NERC and the entire industry."

Cook will assist with the transition to a new general counsel, and stay on at NERC in a part-time capacity.
"It has been my deep privilege to work with the men and women of the electricity industry these many years," Cook said. "We are all better off because of their strong commitment to the reliability of the bulk power system of North America."

NERC has begun a search for Cook's replacement in coordination with Russell Reynolds Associates, who will work closely with NERC leadership and Human Resources throughout the selection process. Cauley expects to bring his recommendation to the NERC Board of Trustees in February 2012.

NERC stakeholders who want to recommend candidates for the position should submit names and appropriate contact information to Lawrence Klock, managing director at Russell Reynolds Associates (larry.klock@russellreynolds.com) or Thomas Linquist, executive director (thomas.linquist@russellreynolds.com), no later than November 4. A full position description and qualification requirements can be received by emailing Klock or Linquist.

Chief Security Officer Accepts Appointment to Department of Homeland Security

Mark Weatherford, vice president and chief security officer at the North American Electric Reliability Corporation (NERC), has been appointed to the position of Deputy Under Secretary for Cybersecurity for the National Protection and Programs Directorate at the Department of Homeland Security. The appointment was announced by DHS Secretary Janet Napolitano, and is effective mid-November.

"Mark's appointment is a great honor and a testament to his expertise in the field of cybersecurity," said Gerry Cauley, president and chief executive officer at NERC. "During his time at NERC, he has forged industry and government partnerships that will continue long after his departure."

Weatherford joined NERC in July 2010 after serving as chief information security officer for the State of California under former Governor Arnold Schwarzenegger. He was awarded SC Magazine's "CSO of the Year" award in 2010. Weatherford began his career as a cryptologic officer in the U.S. Navy.

"It has been an honor to work at NERC and with the dedicated professionals in the electric industry in both the United States and Canada. NERC has one of the most challenging cybersecurity missions of any critical infrastructure in the country, and the Nation can be assured that they take that mission seriously," Weatherford said. "We have made tremendous progress during my tenure at NERC, but much remains to be done and I'm confident in the commitment to carry that progress forward."

Cauley has named Matthew Blizard, currently the manager of Policy and Coordination for Critical Infrastructure at NERC, to replace Weatherford. Blizard has 30 years of experience in the U.S. Coast Guard managing security, mission support and Coast Guard operations.

Compliance

Update on Compliance Application Notice Progress

As part of its ongoing effort to rewrite existing Compliance Application Notices to reflect direction from the NERC Board of Trustees and input from the industry, there has been much activity on the CANs website. The industry's responses have been received and are appreciated.

Currently, NERC is in the process of analyzing industry's comments on CANs -0005, -0006, -0007, -0008 and -0018. These CANs are the expected revisions to be posted as final on the NERC Compliance site.

The comment period for the remaining CANs (CANs -0009, -0011, -0012, -0013, -0015, -0022, -0026 and -0028), and now ends October 31. NERC will begin analysis at that time. Other CANs that were posted for comment and are now closed are -0017, -0024, -0029, -0031 and -0039. CANs -0020 and -0030 comment periods are open through November 9.

Also, Bulletin #2011-006, CIP Table Three Entities, has been posted on the NERC website (See *Public Bulletins* on the Compliance web page).

Workshop News

Compliance and Standards joined forces October 26-28 for the Standards and Compliance Workshop in Atlanta. With the themes of maintaining a risk-based focus, prioritizing standards and the Compliance Enforcement Initiative, both groups presented in conjunction, reinforcing the concept of feedback loops among NERC's internal groups, as laid out by President and CEO Gerry Cauley.

Make plans to attend the next Compliance workshop on December 6 in Atlanta. Agenda topics include an About NERC session; JRO/CFR Concurrent Registration; CANs Update; CIP Auditing Issues; Entities' panel discussion on successful audits; Enforcement Direction; and the 2012 CMEP Implementation Plan. Click here for workshop registration and here for hotel registration.

2012 Audit Worksheets Posted

Reliability Standard Audit Worksheets (RSAW) required for the Tier 1 requirements identified in the 2012 Actively Monitored List have been posted to the NERC website, under the RSAW tab.

The RSAWs can be downloaded as a set or individually by Reliability Standard number. Regional Entities and registered entities are reminded to check the NERC website regularly to ensure the latest versions are being used. The RSAWs are updated on an as-needed basis and notifications are only provided for major postings. If you have any questions or comments regarding the RSAWs contact Craig Struck.

Critical Infrastructure

NERC Opened First Grid Security Conference in New Orleans

The North American Electric Reliability Corporation opened its first grid security conference October 19 in New Orleans with more than 260 security professionals in attendance.

Gerry Cauley, NERC president and chief executive officer, delivered the welcoming address and opening keynote.

"The battle to secure the grid is ongoing and will continue into the future. The ability to continue taking advantage of advances in technology, while ensuring effective levels of security, is critical to our ability to operate," Cauley said. "The 2011 Grid Security Conference is one of the vehicles NERC is using to advance information sharing between NERC, the government and the electricity industry."

GridSecCon brings together industry and government security to deliver a comprehensive education and networking event. More than 20 education sessions are scheduled on topics ranging from *Advanced Persistent Threat*, *Industry Best Practices in Grid Security*, and *Electric Facility Threats and Violence.*
"NERC's goal at this conference is to provide security professionals with real tools and information that they can take back to their companies and improve their security posture," said Mark Weatherford, chief security officer at NERC. "The wide representation from organizations across the United States and Canada indicates the need for an event dedicated to electricity sector cybersecurity."

Other speakers include Department of Homeland Security Acting Deputy Under Secretary for Cybersecurity Greg Schaffer; Lofty Perch President and Chief Security Scientist Mark Fabro; and Tiago Alves de Jesus, from the Royal Canadian Mounted Police.

NERC plans to sponsor GridSecCon annually for industry security professionals. For more information on NERC's cybersecurity program, please visit the website. Public presentations will be posted there after the conference.

Reliability Assessment and Performance Analysis

NERC Launches Demand Response Availability Data System Website

The North American Electric Reliability Corporation (NERC) launched a system that collects information to measure demand response contributions to the reliability of the bulk power system.

The Demand Response Availability Data System (DADS) will provide a basis for projecting the impacts of both dispatchable and non-dispatchable demand response on capacity planning and operational reliability. Demand response enrollment and event information will be collected and assessed on a semi-annual basis with summer and winter reporting periods.

"Demand response is a relatively new resource, and both NERC and the industry need to measure its performance in order to gauge its benefits and impacts on reliability," said Mark Lauby, vice president and director of Reliability Assessment and Performance Analysis at NERC. "Comprehensive performance measures will help develop more confidence in demand response use."

Demand response is one of many resources needed to satisfy the increasing demand for electricity in North America. Capacity and ancillary services provided by demand response help ensure resource adequacy, while providing operators with additional flexibility in maintaining operating reliability.

DADS will allow NERC to receive, manage, assess and share data on demand response programs, products and services administered by retail and wholesale entities throughout North America. This data collection system will provide a basis for counting and validating demand response resources as part of meeting operational and resource reliability requirements.

Visit the DADS website by clicking here.

Reliability Risk Management

Reliability Risk Management Group Formed

On September 26, NERC President and CEO Gerry Cauley announced the consolidation of the Event Analysis and Investigations and Situation Awareness

groups. The new human performance initiative also was consolidated into this new group.

This organizational change to consolidate group resources and to leverage the diverse experience and expertise strategically improves NERC's commitment to reliability excellence and risk management. This new group, Reliability Risk Management (RRM), will allow for more efficient analysis of events on the bulk power system, as they manage the information from "cradle to grave."

"This group will ensure reliability of the bulk power system by being the creditable source of information for grid system health, while conducting technically sound event analysis and investigations of events and disturbances," said Earl Shockley, director of RRM. "We also will continue providing timely lessons learned and needed reliability industry alerts to industry stakeholders."

The primary functions of the newly formed group are:

- Capture and report creditable system awareness information for bulk power system events and system conditions.
- Conduct robust event analysis using cause analysis and risk-based methods.
- Facilitate and ensure lessons learned and any necessary reliability communications are issued to industry stakeholders in a timely manner.
- Retain a strong enforcement authority through any necessary investigations that are independent, objective and at a level consistent with the expectations of the industry and government.

SAFNR V2 Project Updates Previous System

NERC is updating the project that provides real-time system operational information to the 12 Reliability Coordinators basis for FERC, NERC and the eight Regional Entities. Situation Awareness for FERC, NERC and the Regional Entities Version 2 (SAFNR V2) will replace the current SAFNR V1 displays, currently provided by individual Regional Coordinators, with a centralized system that presents for NERC staff with a common look among the Regional Coordinators; with overview information at an interconnection level with the ability to drill into the Regional Coordinators' transmission systems for greater detail; and with extended data retention for trending purposes.

The project currently is in the development and implementation stage. The project has an aggressive schedule to complete the software applications, the visual displays, and to have all subscriber agreements in place during the first quarter of 2012. Six of the Regional Coordinators have successfully mapped their SAFNR V2 operational data to the project consultant. The remaining Regional Coordinators will begin mapping their data in the next few weeks. The SAFNR V2 applications have met the SAFNR V2 project team's design concepts, and the end users should be pleased with the final product.

Standards

Nomination Time for Standards Committee

NERC is accepting nominations for stakeholders to serve on NERC's Standards Committee. There are 10 seats available and nominations are open through November 1.

Any interested stakeholder is eligible and may self-nominate or be nominated by a third party using the 2012-2013 term nomination form. These forms are posted on the Standard Committee's Nominations and Elections page as they are received.

The Standards Committee reports to NERC's Board of Trustees, and provides executive and strategic oversight on NERC's standards activities. The Committee depends on the stakeholder community to identify volunteers to fill vacant seats and to elect strong representation for their segments.

The Standards Committee is composed of two representatives elected from each of the 10 industry segments that make up the Registered Ballot Body. If the industry does not elect at least two Canadian members, the Canadian nominees receiving the next

highest percentage of votes within their respective segment(s) will be designated as members, as needed, to achieve a total of two Canadian members. While other Standards Committee members are elected for two-year terms, Canadian members elected in this manner serve for one-year.

The balanced representation on the Committee is designed to ensure that NERC's standards development activities are fair and balanced, and effectively meet industry reliability needs. To ensure continuity on the Committee, the two-year terms in each segment are staggered, with an annual election held each fall. This means individuals elected from the current slate of nominees will serve from January 1, 2012 through December 31, 2013.
After the nomination period ends on November 1, an election will be conducted for any segment in which there are multiple nominees. To be elected, a nominee must capture a simple majority of the votes from the segment, and if no nominee captures a simple majority, then the two candidates receiving the most votes will compete for the seat in a runoff election.

Standards Committee members are expected to participate in formal monthly Committee meetings (generally eight half-day conference calls, plus two-day quarterly meetings in person), as well as subcommittees and working groups. Committee members also are encouraged to keep members of their segments informed about and engaged in NERC standards development activities.

Appendix 4B of the NERC Rules of Procedure provides more detail about the Standards Committee election process. The Committee's charter and other relevant documents are available on the Standards Committee's Related Files page.

Addressing FERC Order 754

A technical discussion concerning the Federal Energy Regulatory Commission's Order 754 (Single Point of Failure) took place October 24-25 at FERC. Attendees representing FERC, NERC and industry experts on system protection and planning focused on the Order's concern with protection system failures. Discussions included voluntary standards from 1997, standards currently in effect, stakeholder practices, and some regional criteria. The June 14, 2004 Westwing Outage, in particular, was discussed at length and is one of three significant events referenced in a NERC advisory to industry (issued March 30, 2009) that concerns protection system single point of failure. To date, NERC has identified five events which involved single point of failure.

The technical discussion fulfilled the initial directives from Order 754 and concluded with consensus among participants that there is a reliability concern involving single point of failure that requires additional study. Ultimately, the issue may involve transmission planning standards TPL-001-004, which specify bulk electric system performance for certain system protection failures. It was clear from the discussion and subsequent consensus that system performance requirements are achieved jointly through collaboration between planning and protection engineers.

Before concluding, the group formulated a problem statement with several action items for additional development in a joint meeting of the NERC System Protection and Control Subcommittee and the Transmission Issues Subcommittee scheduled for December 6-8 in Fort Worth, Texas. Additionally, a NERC standards project page (Order 754) and distribution list has been created to the keep industry abreast of activities relevant to this issue. With insight from the technical discussion informing Order 754-related initiatives underway, a successful outcome should be achieved that will complement standards currently filed for approval and ultimately enhance reliability.

The most significant next step is the preparation of a data request to the industry in accordance with the NERC Rules of Procedure, Section 1600. For inclusion on email notices regarding activity on Order 754, contact Scott Barfield or call 404-446-9689.

Update: 2012-2014 Reliability Standards Development Plan

In October, the Standards Committee was asked to approve the 2012-2014 Reliability Standards Development Plan. The Plan, developed over the past several months with input from a number of stakeholders, was approved with modifications. Major modifications include the addition of an update on regional standards, a regional standards development work plan, and descriptions of the various regional projects currently in or planned for development. Other modifications deal primarily with structure and formatting changes, as well as additional editorial suggestions.

The next step is to present the Plan to the Board of Trustees for approval at the November 3 meeting in Atlanta. Following board approval, NERC will file the Plan with applicable Electric Reliability Organization governmental authorities.

Standard Drafting Team Vacancies

Any industry stakeholder meeting the indicated qualifications for one of the following three vacant appointments may submit a self-nomination form to sarcomm@nerc.com. Further instructions can be found on the Drafting Team Vacancies page on NERC's website.

Project 2007-06 System Protection Coordination
Seeking an individual from a Canadian entity with experience in coordination of protection systems (new installations and revisions).

Project 2007-12 Frequency Response
Seeking an individual representing Transmission Dependent Utilities with experience in analyzing or modeling frequency response.

Project 2010-07 Generator Requirements at the Transmission Interface
Seeking an individual, preferably from a Regional Entity, with a compliance role or background. Candidate should have experience working with generation, transmission, or both. The candidate should also be familiar with the history of the GOTO Ad Hoc Group, recent registration activity, and the work of the Project 2010-07 SDT.

In addition to these vacancies, the **Project 2007-17 Protection System Maintenance and Testing** drafting team is seeking individuals with experience in developing, managing, or supporting a maintenance program or testing a program for one or more of the following: generator protection systems, transmission protection systems, under-frequency load shedding equipment, under-voltage load shedding equipment, and/or special protection systems. The specific focus of this solicitation is to add members representing smaller entities. If you are interested in serving on this drafting team, please complete this project-specific nomination form by September 23, 2011. More details are included on the Project 2007-17 project page. Please contact Andy Rodriquez with questions regarding the vacancies.

Filings

NERC Filings to FERC

(click on the link for full filing)

October 3, 2011

Motion to Intervene and Comments regarding City of Holland, Michigan Board of Public Works

NERC submits a Motion to Intervene and Comments in response to the appeal of the City of Holland, Michigan Board of Public Works. *Docket No. RC11-5-000*

October 19, 2011

Petition for Approval of a Revised Transmission Planning System Performance Requirements Reliability Standard TPL-001-2 and Five New Glossary Terms and for Retirement of Four Existing Reliability Standards

NERC submits a petition for approval of a Revised Transmission Planning System Performance Requirements Reliability Standard TPL-001-2 and five new glossary terms and for retirement of four existing Reliability Standards. *Docket No. RM_-__-000*

NERC Filings in Canada, click here

(click on the link above for full filing)

September 30, 2011

NERC submits a Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Find Fix and Track (FFT) Informational Filing.

Careers at NERC

General Counsel
Location: Washington, DC
Contact Larry Klock at Russell Reynolds Associates

Manager of Reliability Risk Management
Location: Atlanta
Details

Associate General Counsel and Director of Compliance Enforcement
Location: Washington, DC
Details

Manager of Notice of Penalty (NOP) Development
Location: Washington, DC
Details

Senior Compliance Enforcement Engineering Analyst
Location: Washington, DC
Details

Data Management System Specialist
Location: Washington, DC
Details

Manager of Compliance Analysis, Reporting, and Tracking
Location: Washington, DC
Details

Compliance Auditor
Location: Atlanta
Details

Event Investigator
Location: Atlanta
Details

Attorney
Location: Washington, DC
Details

Attorney
Location: Washington, DC
Details

Business Analyst
Location: Atlanta
Details

Manager of Power System Analysis
Location: Atlanta
Details

Reliability Standards Analyst
Location: Atlanta
Details

Reliability Standards Adviser
Location: Atlanta
Details

Standards Specialist
Location: Atlanta
Details

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

October 31, 2011

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: NERC Analysis of NERC Standard Process Results Third Quarter 2011 in Docket Nos. RR06-1-000, RR09-7-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") submits its Analysis of NERC Standards Process Results for the Third Quarter 2011 ("Ballot Results Filing"). This filing is submitted in response to the Federal Energy Regulatory Commission's ("FERC") January 18, 2007 Order[1] requiring NERC to closely monitor and report to FERC the voting results for NERC Reliability Standards each quarter for three years. In a subsequent order issued on September 16, 2010, the Commission renewed and expanded on its directive for an additional three years.[2]

The Ballot Results Filing is included as **Attachment A** to this filing. The Ballot Results Filing addresses ballot results during the July 1, 2011 to September 30, 2011 time frame and includes NERC's analysis of the voting results, including trends and patterns of stakeholder approval of NERC Reliability Standards. NERC requests that FERC accept this filing as compliant with the renewed directive in the September 16, 2010 Order to submit quarterly reports for an additional three years from the date of the order.

Respectfully submitted,

/s/ Willie L. Phillips
Willie L. Phillips
Attorney for North American Electric Reliability Corporation

cc: Official service list in Docket No. RR06-1-000

[1] *Order on Compliance Filing*, 118 FERC ¶ 61,030 at P 18 (2007).
[2] *Order on the Electric Reliability Organization's Three-Year Performance Assessment*, 132 FERC ¶ 61,217 at P 85 (September 16, 2010).

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Analysis of NERC Standards Process Results

Third Quarter 2011

October 31, 2011

RELIABILITY | ACCOUNTABILITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Introduction 1

Background: NERC's Revised Processes for Developing Standards 1

This Report 1

Analysis of Q3 2011 Standards Ballot Results 3

Q3 2011 Ballots and Comparison to Baseline Data 5

Conclusion 8

Appendix A 9

Summary of Process Revisions in NERC Standards Processes Manual 9

Appendix B 12

Types of Standards Projects 12

Appendix C 13

Phases in Standard Projects 13

Introduction

Background: NERC's Revised Processes for Developing Standards

NERC develops Reliability Standards in accordance with Section 300 of its Rules of Procedure and the NERC *Standard Processes Manual*, which is included as Appendix 3A to the NERC Rules of Procedure.[1] The current *Standard Processes Manual* was approved by the Federal Energy Regulatory Commission ("FERC" or the "Commission") in September 2010,[2] amended August 2011,[3] and incorporates a number of process revisions intended to maintain the openness and inclusiveness of the standards development process, while improving efficiency and the quality of standards and interpretations. A summary of these revisions is included for convenience as Appendix A to this report.

To date, no project initiated under the revised *Standard Processes Manual* has been completed. All projects discussed in this report, and for which ballots were completed in the third quarter 2011, were initiated under the *Reliability Standards Development Procedure Version 7,* but will be completed under the new processes.

This Report

There are two purposes for producing this report. First, this report and future versions will provide NERC, its Board of Trustees, committees, and industry stakeholders information to support future decisions concerning improvements to the standards development process. Second, this report is responsive to directives from FERC directing NERC to monitor, analyze, and report on the results of its standards development processes.[4]

At the end of each calendar quarter, NERC will update this report by incorporating results from the most recent calendar quarter to monitor and report progress on improvements to various aspects of the standards development process. The first section of this report provides an overview and analysis of ballots conducted during the third quarter of 2011. The second section compares timelines for the projects balloted in the third quarter 2011 against baselines provided in the report filed on January 31, 2011, on the time to complete each phase of standards development. The comparison to the historical baselines is responsive to the

[1] NERC's Rules of Procedure are available at: http://www.nerc.com/page.php?cid=1|8|169.

[2] *Order Approving Petition and Directing Compliance Filing*, 132 FERC ¶ FERC 61,200 (September 3, 2010).

[3] *Letter Order Approving Standard Processes Compliance Filing* (August 25, 2011)

[4] *See Order on Compliance Filing,* 118 FERC ¶ 61,030 (January 18, 2007). *See also, Order on the Electric Reliability Organization's Three-Year Performance Assessment,* 132 FERC ¶ 61,217 at P 85 (September 16, 2010) ("Three-Year Assessment Order"). Specifically, the Three-Year Assessment Order directed NERC to analyze:

(i) the time required to complete projects (excluding urgent action projects);
(ii) the time required to complete projects initiated in response to NERC's urgent action progress (including whether or not a permanent fix was implemented within the sunset period); and
(iii) the time required to complete projects in response to Commission directives. The analysis should include data on the time required for each stage of the process. For example, the analysis should document the time required to move a proposed Reliability Standard from a Standards Authorization Request to the NERC Board, and then to the Commission.

Commission's directive to analyze the time required to complete each phase of the standards development process. NERC staff and the Standards Committee will use this analysis to monitor successes and to identify opportunities for improvements.

Analysis of Q3 2011 Standards Ballot Results

From July 1, 2011, through September 30, 2011, NERC conducted ballots for four separate Reliability Standards projects. Table 1 summarizes these ballot events. A complete record for each project is available on NERC's website on the Ballot Results webpage.[5]

Table 1

Project Type[6]	Project Number & Name	Q3 Ballot Events	Status
Revision	2006-02 - Assess Transmission Future Needs and Develop Transmission Plans	Recirculation Ballot of one Standard	Adopted by NERC BOT 8/2011
Revision	2006-06 - Reliability Coordination	Recirculation Ballots of three Standards and conforming changes to another Standard	Four standards adopted by NERC BOT 8/2011. (Work on three additional standards that were not balloted in Q3 2011 is ongoing.)
New	2007-09 - Generator Verification	Initial Ballot of two Standards	Ongoing
Revision	2007-17 - Protection System Maintenance and Testing	Initial Ballot of one Standard	Ongoing

During the third quarter 2011, two projects had balloted standards that were approved by their ballot pools and adopted by the NERC Board of Trustees on August 4, 2011. The first of these projects was Project 2006-02 - Assess Transmission Future Needs and Develop Transmission Plans. Although the ballot was for a single standard, the project involved the consolidation of requirements from six standards into a single standard. The recirculation ballot achieved a very high quorum of almost 95 percent, and a weighted segment approval of just over 75 percent. The NERC Board of Trustees adopted the standard and a petition for regulatory approval was submitted on October 19, 2011.

The second project was Project 2006-06 - Reliability Coordination. For Project 2006-06, three standards were approved by the ballot pool and adopted by the NERC Board of Trustees on

[5] The Ballot Results webpage is available at: https://standards.nerc.net/Ballots.aspx.

[6] Appendix A to this report provides a brief description of each type of standards project.

August 4, 2011. The project involves six standards, including three that were balloted in the third quarter. The standards drafting team ultimately determined that a recirculation ballot of these three standards was appropriate, based upon the consensus achieved in a previous ballot that was concluded in the second quarter 2011. These three standards were balloted individually, and each achieved high quorum and weighted ballot pool approvals of between 75 and 78 percent.

The NERC Board adopted the three standards, along with conforming changes to a fourth standard on August 4, 2011, and a petition for regulatory approval of the four standards is being prepared for filing in the fourth quarter 2011. The drafting team is continuing work on three other standards that are part of this project (this includes additional modifications to the standard being filed with a conforming change).

Two other projects that were balloted during the third quarter require additional work and are ongoing: Project 2007-09 - Generator Verification, and Project 2007-17 - Protection System Maintenance and Testing.

Project 2007-09 involves development of five standards, and, like Project 2006-06, the standards are at different points in development. Two of the standards in Project 2007-09 underwent separate initial ballots during the third quarter.[7] Both ballots achieved a very high quorum, but low weighted segment approvals of 46.53 percent and 18.23 percent. The other three standards were posted for comment concurrent with the two ballots, and the drafting team is considering comments received on all five standards to determine what revisions to the standards are needed.

Project 2007-17 is a project to merge four standards into a single standard. At the end of the second quarter, a recirculation ballot was conducted that narrowly failed to achieve the required two-thirds weighted segment approval. The drafting team for this project reevaluated the comments from the successive ballot and made additional revisions to clarify certain requirements, along with revisions to supporting technical references. In accordance with the *Standard Processes Manual*, the standard development process was reinitiated with the posting of a Standards Authorization Request ("SAR") and revised standard. Because the standard was not new to stakeholders, the Standards Committee waived the initial comment period and an initial ballot was conducted. The initial ballot achieved a quorum, but the standard again failed to achieve the required weighted segment approval by a few percentage points. Development will continue.

[7] Stakeholders have requested that individual standards be balloted separately for projects that involve multiple standards, and during the third quarter 2011 NERC began adopting this approach when possible.

Q3 2011 Ballots and Comparison to Baseline Data

In the version of this report filed on January 31, 2011, NERC provided baselines for each phase of development for standards projects. These baselines were established by grouping all NERC standards projects from 2006 through 2010 into four categories (new standards, revisions to existing standards, expedited projects, and interpretations) and then averaging the times for each phase of development within each group.

In this section of this and future reports, NERC will compare the projects balloted each quarter against these baselines. These comparisons may highlight anomalies initially, but over time the comparison will help to identify trends in the time required for various phases of standards development.

During the third quarter of 2011, ballots were conducted for four standards projects. Three of the standards projects balloted in the third quarter are categorized as "revisions to existing standards" for the purposes of comparing to baselines. The remaining project is categorized as a project to develop "new standards" for this purpose. Chart 1 compares the development phases for each of the four revision projects in this quarter to the baseline. Chart 2 compares the development phases of the project to develop new standards to the baseline.

A discussion of the development phases for these projects is included below.

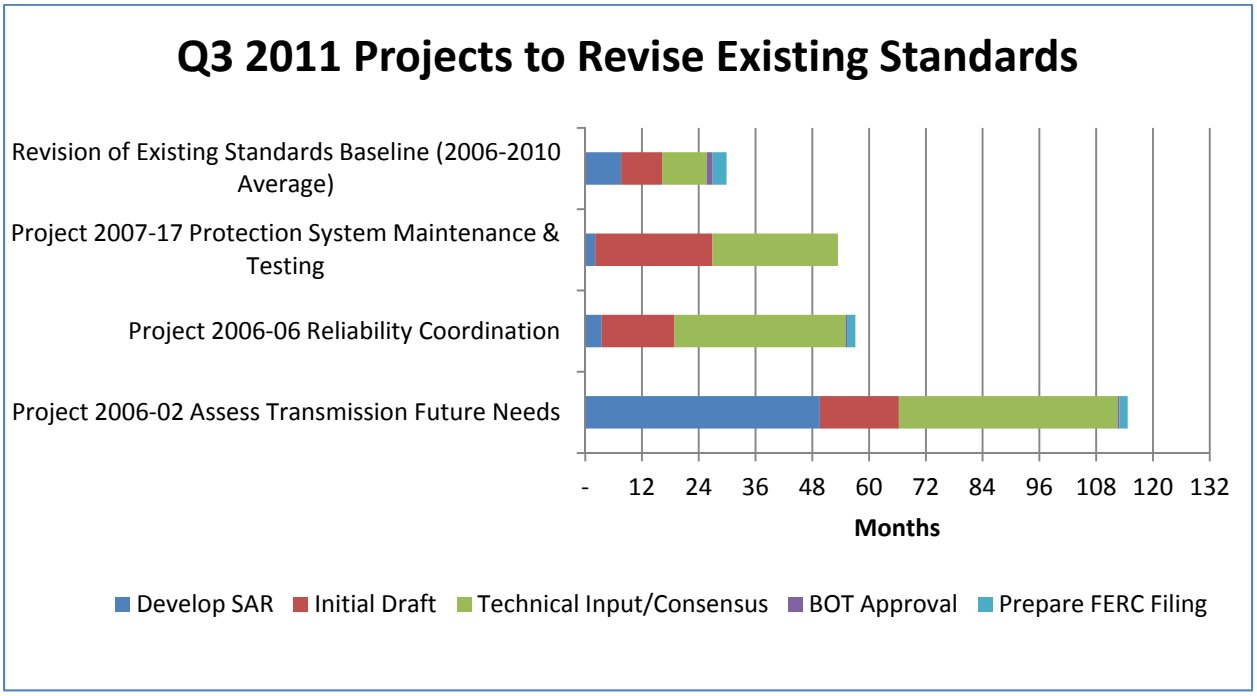


Chart 1

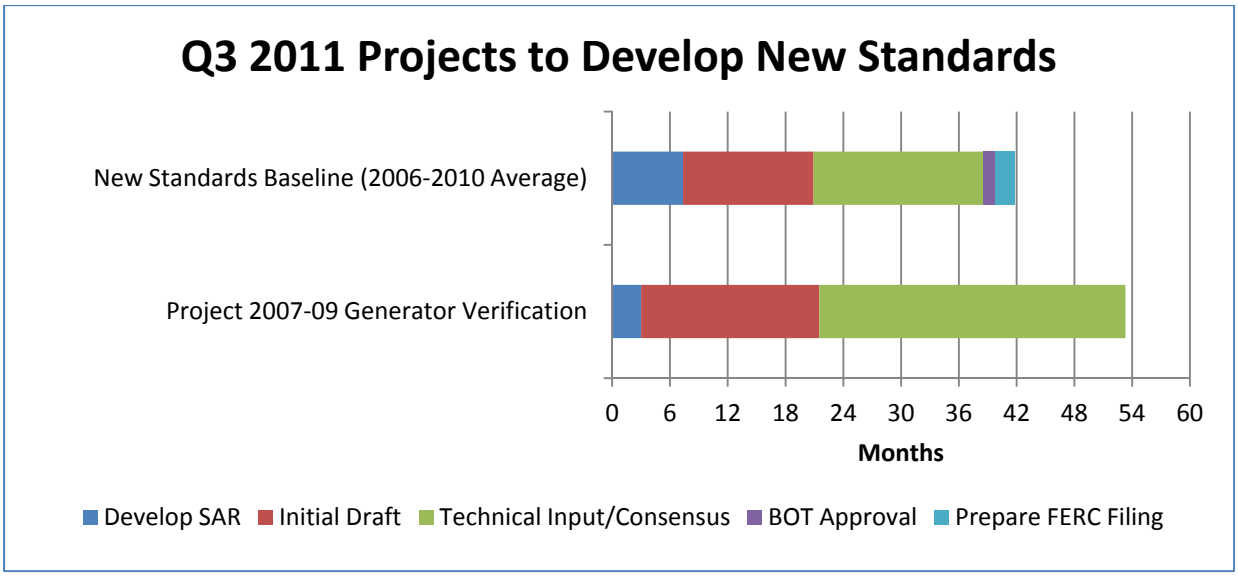


Chart 2

No ballots of "interpretations" or "expedited projects" were conducted during the third quarter 2011.

SAR Development Phase. For all projects balloted in the third quarter of 2011 with the exception of Project 2006-02,[8] the SAR was finalized quickly after being posted for industry review. One project, 2007-17, required that the SAR be posted a second time when the project was reinitiated after a recirculation ballot failed to achieve industry approval. No additional time was included in the SAR development phase for the purpose of this analysis because the drafting team did not make any substantive revisions to the original SAR. From 2006 to 2010, SAR development times averaged eight months for a project to revise one or more existing standards. The SAR development period for projects balloted during the third quarter of 2011 averaged less than three months.

Initial Draft Phase. All three projects balloted in the third quarter 2011 required a longer period of time than the baseline for the comparable type of project, with the initial draft phases of the three projects requiring between 15 and 24 months to complete. For comparison, the 2006-2010 average duration of this phase of standard development was between eight and nine months for projects to revise standards, and almost 14 months for projects to develop new standards. One factor that may account for the difference between the projects being balloted in the third quarter and the 2006-2010 baseline is that many of the projects included in the baseline included a single standard, whereas all of the projects balloted in Q3 2011 include multiple standards. In addition, Project 2006-06 involves a number of issues that require coordination with other drafting teams to ensure a cohesive approach to requirements involving real-time operations and communications.

[8] As discussed in the *Analysis of NERC Standard Process Results Second Quarter 2011,* filed July 29, 2011, the SAR development period for Project 2006-02 was more than 49 months, in part because SAR development for Project 2006-02 was placed on 'hold' for almost two years before the SAR was finalized while waiting for completion of Version 0 standards.

Technical Input Phase. Technical input from the industry is received through the formal and informal posting periods. Between each posting, the drafting team reviews the feedback received from stakeholders and makes revisions to the standard or standards. For a formal posting, drafting teams are also required to respond to each stakeholder comment. Thus the technical input phase includes periods of time when standards and associated documents are posted for industry review – typically either for 30 or 45 days – alternating with periods of time during which the drafting team is reviewing the input provided, revising the standards and associated documents, and preparing responses to the comments received. The technical input phase is essentially a highly-organized dialogue between the drafting team and other industry stakeholders.

For the three revision projects balloted during the third quarter of 2011, this phase has taken, on average, 36 months and is ongoing for two of the three projects. For Project 2007-09, in which the two standards balloted are new standards, the technical input phase has taken 32 months to date, and is ongoing. For all projects revising existing standards from 2006 to 2010, the average duration of the technical input phase was nine and a half months, and for projects to develop new standards the average duration of this phase was approximately 18 months. As with the initial draft phase, conclusions about the comparison between this quarter's projects and the baseline must consider that the baseline averages developed for 2006 to 2011 involved many projects to develop a single standard while all three of the projects this quarter are complex projects involving multiple standards and coordination with other projects.[9]

Board of Trustee Adoption. The period of time between ballot pool approval of a standard and Board of Trustee adoption of the standard varies depending on the number of other items that require action by the board. (The board has a fixed schedule of face-to-face meetings, and supplements its face-to-face meetings, as needed, to ensure prompt action when necessary to meet ERO obligations.) In the third quarter of 2011, five standards from two projects (one from Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans, and four from Project 2006-06 Reliability Coordination) were presented to the Board of Trustees for adoption. All of the standards were presented to the Board for adoption within two weeks of ballot pool approval.

Filing with Regulatory Authorities. During the third quarter of 2011, NERC filed a petition for approval of two interpretations of the same standard, EOP-004. These interpretations were approved by the Board of Trustees in November 2010. Once the Board of Trustees approves a standards project, NERC staff routinely prepares a draft filing, which is then circulated internally for comment. If substantive edits are required in response to comments received, then additional drafts may be circulated. After a consensus is reached on the draft, NERC finalizes the filing and compiles supporting exhibits for submittal to FERC.[10]

[9] NERC has recognized this constraint and when the baselines are updated with 2011 data will provide additional analysis to account for the differences between projects.

[10] NERC also files each new or revised standard with each applicable Canadian governmental authority.

Conclusion

NERC and the Standards Committee continue to look for opportunities to improve the efficiency and effectiveness of the standards process. One possible improvement that was tested during the third quarter 2011 was the practice of balloting each standard in a project individually. Some drafting teams have expressed concerns that this may result in a less efficient process if standards approved by the ballot pool must ultimately be changed after approval in order to conform to changes made to other standards that are part of the same project. It will be important to monitor each project to determine when separate balloting may provide additional information to assist the drafting team in developing a technically sound standard and reaching consensus more quickly. NERC continues to recognize challenges in communicating changes made by drafting teams between a recirculation ballot and the previous ballot, and has undertaken steps to improve active stakeholder participation in recirculation ballots by improving communications to stakeholders to identify changes made in response to stakeholder input before standards are posted for recirculation ballots.

Appendix A

Summary of Process Revisions in NERC Standards Processes Manual

NERC's *Standards Processes Manual* was developed to replace *Reliability Standards Development Procedure Version 7 (RSDP7)* as Appendix 3A of the NERC Rules of Procedure. The *Standard Processes Manual* was approved by FERC in September 2010.[11]

One of the significant modifications in the new *Standard Processes Manual* is the method used to achieve consensus – through parallel comment and ballot periods, which are conducted early in the process and continue until consensus is achieved. This change appears to be increasing the quality and quantity of feedback that the standards drafting teams are receiving on proposed standards. Because drafting teams are encouraged to make significant changes to the standards between successive ballots without a pre-ballot review period, this modification gives drafting teams the flexibility to revise the standards to take account of the comments received and immediately re-ballot without the separate, successive formal comment and pre-ballot review periods that were required in the *RSDP7*.

This added efficiency means drafting teams begin ballot periods earlier in the development process. While initial ballot results may receive lower approval ratings in the initial stages, as approval increases, the successive ballot process provides a clear indication of the move toward industry consensus.

Just as in the *RSDP7*, an entity or individual that desires to vote on proposed reliability standards must be a member of the registered ballot body. The registered ballot body includes all entities or individuals that qualify for one of ten stakeholder segments and have registered with NERC as potential voting participants. Each member of the registered ballot body is eligible to participate in the voting process and ballot pool for each standard action. The ten stakeholder segments are:

- Transmission Owners
- Regional Transmission Organizations and Independent System Operators
- Load-Serving Entities
- Transmission Dependent Utilities
- Electric Generators
- Electricity Brokers, Aggregators, and Marketers
- Large Electricity End Users
- Small Electricity Users
- Federal, State, and Provincial Regulatory or other Government Entities
- Regional Reliability Organizations and Regional Entities

[11] *Order Approving Petition and Directing Compliance Filing*, 132 FERC ¶ FERC 61,200 (September 3, 2010).

Each standard ballot action has its own ballot pool, populated by interested members of the registered ballot body, including those with specific technical expertise of the subject matter. The individuals that join a ballot pool respond to a pre-ballot e-mail announcement associated with each reliability standard ballot action. The ballot pool size varies, and is based on the standard and the topic. The ballot pool votes to approve or reject each standard action. Specifically, the ballot pool votes determine: (1) the need for and technical merits of a proposed standard action; and (2) that appropriate consideration was given to views and objections received during the development process.

The reliability standards development process may include three types of ballots: an initial ballot, a successive ballot, and a recirculation ballot. An initial ballot is conducted during the last 10 days of a 45-day comment period; successive ballots are conducted during the last 10 days of a 30-day comment period. Following an initial or successive ballot, the drafting team is obligated to respond to each stakeholder comment. The drafting team must consider the issues raised in stakeholder comments to determine whether revisions to the standard and its associated implementation plan should be made.

If the comments submitted during the initial comment period and ballot indicate a need for significant changes, then the drafting team will produce a new draft standard, even if the weighted segment approval is 66.66% or greater. When a drafting team makes significant revisions to the standard, the next ballot held is a successive ballot conducted during the last 10 days of a parallel 30-day comment period. Votes cast by the ballot pool in the initial ballot are not counted in a successive ballot. Each ballot pool member must cast a new vote.

If needed, the *Standard Processes Manual* allows for multiple, successive ballots to obtain the two-thirds majority on a proposed standard. Once the comments from a successive ballot are addressed by the drafting team and there is no need for significant changes to the standard, the standard proceeds to a recirculation ballot.

A recirculation ballot does not have a comment period, and votes cast in the most recent successive ballot are carried forward. If a member of the ballot pool chooses to vote in the recirculation ballot, the vote cast by that member in the successive ballot is updated.

Approval of a standard action requires that both:

- A quorum is established. This requirement is met when at least 75% of the members of the ballot pool for the standard action submit a response with an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast are affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

The following process is used to determine whether there are sufficient affirmative votes.

- The number of affirmative votes cast in each segment is divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for

each segment. Abstentions and non-responses are not counted for the purposes of determining the fractional affirmative vote for a segment.

- If there are less than ten entities that vote in a segment, the vote weight of that segment is proportionally reduced. Each voter within that segment voting affirmative or negative receives a weight of 10% of the segment vote. For segments with ten or more voters, the regular voting procedures are followed.
- The sum of the fractional affirmative votes from all segments divided by the number of segments voting is used to determine if a two-thirds majority affirmative vote has been achieved. (A segment is considered as "voting" if any member of the segment in the ballot pool casts either an affirmative or a negative vote.) [12]
- A standard is approved if the sum of fractional affirmative votes from all segments divided by the number of voting segments is equal to or greater than two thirds.

On March 17, 2011[13] the Commission approved a modification to NERC's Rules of Procedure, Rule 321, that was developed to respond to FERC's March 18, 2010 Order directing NERC to propose modifications to NERC's Rules of Procedure was approved by the Commission.[14] Rule 321 lays out specific processes to be used if stakeholders are unable to achieve consensus through the processes in the Standards Processes Manual to present the NERC Board of Trustees with a standard that is responsive to a specific Commission directive.

[12] When less than ten entities vote in a segment, the total weight for that segment is determined as one tenth per entity voting.

[13] *See Order Directing NERC to Propose Modification of Electric Reliability Organization Rules of Procedure,* 130 FERC ¶61,203 (March 18, 2010). *See also,* Compliance Filing of the North American Electric Reliability Corporation in Response to March 18, 2010 Commission Order Directing Revisions to Standards Development Procedure, filed in Docket No. RR08-6-000 (December 23, 2010).

[14] *Order on Compliance Filing,* 134 FERC ¶ FERC 61,216 (March 17, 2011).

Appendix B

Types of Standards Projects

For the purpose of analyzing results of its standards processes, NERC has identified four broad categories of standards projects.

The first category of projects is **Revisions to Existing Standards**. Revisions to existing standards are a significant and an ongoing part of NERC's standards development work, as NERC and industry work to address regulatory directives from FERC, modify standards to address changing technologies and operating conditions, and review standards in compliance with the five-year interval required to maintain ANSI accreditation. Between 2006 and 2010, the average time to complete revisions to existing standards was 30 months.

The second category is **New Standards**. There have been, and will continue to be, occasions where an entirely new standard or group of standards may be needed to address bulk power system reliability. The data collected from 2006 through 2010 show that these projects take longer, on average, than projects to revise existing standards. Between 2006 and 2010, the average time to complete projects to draft new standards was 42 months.

The third category is **Urgent Action/Expedited Projects**.[15] Urgent Action or Expedited Projects are shortened by reducing the time for certain process steps, or by allowing steps that would normally proceed serially to be conducted in parallel. By definition, these projects are expected to have a shorter development time, on average, than most standards projects. On average, the development time for Urgent Action and Expedited Projects from 2006 through 2010 was a little more than 7 months.

The final category is **Interpretations**. Entities that must comply with a reliability standard have the right to request a formal interpretation of a requirement included in a standard. Interpretation projects generally are narrower in scope than other standards projects, but like standards, interpretations are drafted by a drafting team and posted for industry review and ballot. From 2006 to 2010, NERC received a number of requests for interpretation that were absorbed into other projects because drafting teams could not prepare the interpretations without expanding the requirements of the approved standard. For those interpretation requests that were processed, the average time to complete interpretations and file them with regulatory authorities was about 10 months.

[15] Prior to September 2010, the NERC *Reliability Standards Development Procedure* incorporated a process used for developing a standard more quickly than the normal standard development process, which was referred to as the Urgent Action Process. FERC's approval of the *Standard Processes Manual* in September 2010 replaced the Urgent Action process with the Expedited Standards Development Process.

Appendix C

Phases in Standard Projects

NERC has identified five phases in the development of a Reliability Standard. Table 2 identifies those phases.

Table 2

Phases in NERC Reliability Standards Development Projects	
Phase	**Description**
1. SAR Development	from initial draft SAR to SC acceptance of a SAR for posting, including industry ballot of SAR if required
2. Initial Draft Development	from acceptance of SAR to posting of initial draft
3. Industry Technical Input/Consensus Building	from posting of initial draft(s) through ballot pool approval of a recirculation ballot
4. Board of Trustee (BOT) Approval	from ballot pool approval to BOT approval
5. Filing with Regulatory Authorities	from BOT approval to filing

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Standards and Compliance Workshop

October 26-28, 2011

JW Marriott Atlanta-Buckhead
3300 Lenox Road
Atlanta, GA 30326
(404) 262-3344

Wednesday, October 26	Presentation	Presenter
10:00 a.m.- 12:00 p.m.	NERC Standards 101	**Maureen Long**, Director of Standards Process, and **Mallory Huggins**, Standards Specialist
12:00-1:00 p.m.	Lunch for NERC 101 participants	--
1:00-1:40 p.m.	President's Remarks	**Gerry Cauley**, President and CEO
1:40-2:30 p.m.	Standards Development Updates (Reliability Standards Development Plan; Prioritization; Version 0; Active Projects)	**Andy Rodriquez**, Director of Standards Development
2:30 – 3:15 p.m.	Cliff Notes for Standards Participation	**Maureen Long**, Director of Standards Process, and **Laura Hussey**, Standards Process Manager
3:15-3:30 p.m.	Break	--
3:30-4:30 p.m.	Feedback Loops: Events Analysis, Compliance, and Standards	**Roman Carter**, Manager of Situation Awareness, **Val Agnew**, Manager of Compliance Standards Interface and Outreach, and **Herb Schrayshuen**, VP of Standards and Training
4:30-5:00 p.m.	General Q&A Session	**Val Agnew**, Manager of Compliance Standards Interface and Outreach, and **Herb Schrayshuen**, VP of Standards and Training

Thursday, October 27	Presentation	Presenter
8:00-9:00 a.m.	FERC Commissioner Remarks	**Commissioner Cheryl LaFleur**
9:00-9:30 a.m.	Rapid Development Project: Project 2010-05.1—Phase 1 of Protection Systems: Misoperations	**Maureen Long**, Director of Standards Process
9:30-10:00 a.m.	Interpretations	**Laura Hussey**, Standards Process Manager
10:00-10:15 a.m.	Break	--
10:15 a.m.-12:00 p.m.	Compliance and Enforcement Initiative and the Future Impact on Standards Development	**Rebecca Michael**, Associate General Counsel and Acting Director of Enforcement, and **Val Agnew**, Manager of Compliance Standards Interface and Outreach
12:00-1:00 p.m.	Lunch	--
1:00-3:00 p.m.	Project 2010-017— Definition of Bulk Electric System	**Pete Heidrich**, Chair of Project 2010-17—Definition of BES, Standard Drafting Team, and **Carter Edge**, Chair of Project 2010-17—Definition of BES, Rules of Procedure
3:00-3:15 p.m.	Break	--
3:15-4:00 p.m.	ERO 2012 Implementation Plan and Actively Monitored List	**Kyle Howells,** Compliance Auditor
4:00-5:00 p.m.	Compliance Application Notices (CANs)	**Ben Engelby,** Senior Compliance Specialist, and **Caroline Clouse,** Compliance Specialist

Friday, October 28	Presentation	Presenter
8-8:30 a.m.	Auditors and Compliance Enforcement Authority Training	**Peter Knoetgen**, Director of Training and Accreditation
8:30-9:30 a.m.	Website Update and Available NERC Resources	**Kristin Iwanechko**, Manager of Standards Information, and **Caroline Clouse**, Compliance Specialist
9:30-10:15 a.m.	Critical Infrastructure Protection (CIP) Initiatives at NERC	**Brian Harrell**, Manager of CIP Standards, Training, and Awareness
10:15-10:30 a.m.	Break	--
10:30-11:30 a.m.	CIP Version 5	**Steve Noess**, Standards Development Advisor
11:30 a.m.-12:00 p.m.	General Q&A Session	**Val Agnew**, Manager of Compliance Standards Interface and Outreach, and **Herb Schrayshuen**, VP of Standards and Training

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards and Compliance Workshop Errata

A few items from the workshop require clarification, correction, or follow-up, and we've addressed them below. If you have additional questions or concerns, please contact mallory.huggins@nerc.net.

Correction: In discussing EOP-008-1—Loss of Control Center Functionality, a presenter identified that the standard requires the Reliability Coordinator, Balancing Authority, and Transmission Operator to have a backup facility, but it is only the Reliability Coordinator that is required to have a backup control center facility. All three entities do have to have backup functionality, but only the Reliability Coordinator has to have a backup control center facility (per Requirement R3).

Clarification: As reported during the workshop, the Compliance Application Notice (CAN) process has been revised based on stakeholder input. The October 14, 2011 version of the CAN process is available on NERC's website. The revised CAN process includes a step to use input from the Compliance and Certification Committee, the Standards Committee, stakeholders, and factors surrounding the CAN request to prioritize development of CANs. Involving the Standards Committee in this prioritization is new and hasn't been implemented yet, as the work done since the CAN process was revised (on October 14, 2011) has focused on modifying specific CANs based on Board of Trustees feedback.

Follow-up: Several attendees asked for a reference for writing procedures. Maureen Long recommends *Procedure Writing: Principles and Practices*, by Douglas Wieringa, Christopher Moore, and Valerie Barnes. This paperback was originally written for the Department of Energy to guide the writing of procedures for nuclear power plant operating personnel. It was later revised to appeal to a broader population of procedure writers.

SNLEnergy
POWER DAILY™
Volume 9 Issue 214 **Friday, November 4, 2011**

Water rate pact bodes well for earnings of Calif. electric utilities, analysts say

by Jeff Stanfield

A settlement between four California water utilities and the California Public Utilities Commission's Division of Ratepayer Advocates, filed Nov. 2, is a positive sign for the state's largest investor-owned utilities, whose returns on equities for 2012-2015 will be reset in 2012, analysts with Macquarie Capital (USA) Inc. said in a Nov. 3 report.

The settlement calls for only a very small reduction in ROE requests for the four water utilities: California Water Service Co., San Jose Water Co., California-American Water Co. and Golden State Water Co., Macquarie said in the report.

ROE decisions in water and electric rate cases traditionally have been similar, and since both types of utilities are under the PUC's jurisdiction, the presiding commissioner in the water case is likely to be the same for the electric cases, Macquarie analyst Angie Storozynski, one of the report's authors, said in a Nov. 3 interview. Also, the ratepayer advocates weigh in on electric and water rate cases, so "we think this is a good positive for the electrics," she said.

The water utilities have agreed to lower their 2012-2014 ROEs by 20 to 30 basis points as the parties settled for a 9.99% allowed ROE and equity ratios of 51.35% to 55%, the Macquarie report said.

If approved by the PUC, the settlement would result in a reduction of 20 to 30 basis

Continued on p 12

In this Issue

Click on headline to advance to story

Amid Solyndra controversy, DOE's Chu rallies for federal support of clean energy

NH senators see nation's electric reliability declining, seek FERC review

NRG's Crane: Falling cost of solar could revolutionize hub-and-spoke industry model

First Solar expects 'correction' in oversupplied solar panel market

Progress still targeting year-end closure of merger with Duke

Duke reveals NC rate case recommendation; future case likely as new plants come online

To Market Story

To Market Report

Edwardsport woes aside, Duke charges ahead on $7B power plant construction portfolio

by Jason Lehmann

Duke Energy Corp. is nearing the end of a roughly $7 billion, 2,700-MW fleet modernization program, with new plants expected to be in service later this year and in 2012 in Indiana and the Carolinas.

Duke Energy Carolinas LLC's planned 620-MW combined-cycle Buck plant in Rowan County, N.C., is 96% complete, with the company having spent $625 million on the estimated $700 million project through the third quarter, according to the company's third-quarter earnings slide presentation. The plant is expected to be online later this year.

The 825-MW Cliffside clean coal plant is 93% finished and expected to come online in fall 2012. Duke said through the third quarter it has spent about $1.93 billion on the Rutherford County, N.C., project, with another $475 million of investment planned.

The planned 620-MW combined-cycle Dan River facility in Rockingham County, N.C., is 61% completed and expected to come online by the end of 2012. Like Cliffside and

Continued on p 12

House Republicans vote to subpoena White House Solyndra documents

by Kathleen Hart

Over the strong objections of committee Democrats, Republicans on a House Energy and Commerce Committee panel voted 14-9 to authorize a subpoena for White House communications on the $535 million U.S. Department of Energy loan guarantee to now-bankrupt Solyndra Inc.

"I feel compelled to offer this resolution. … We have exercised restraint … and the administration has resisted our efforts every step of the way," Rep. Cliff Stearns, R-Fla., chairman of the committee's Oversight and Investigations Subcommittee, said at a Nov. 3 meeting called to consider whether to subpoena internal White House communications on the loan guarantee to solar panel manufacturer Solyndra. "We have an obligation to the American people to find out what went wrong with this loan guarantee program."

Rep. Henry Waxman, D-Calif., ranking Democrat on the full committee, argued that the resolution would give Rep. Fred Upton, R-Mich., chairman of the committee, a "blank

© 2011, SNL Financial LC. All Rights Reserved.

check to subpoena the White House when there is no need for this extraordinary step." Arguing that the investigation into Solyndra should be bipartisan, Waxman called the resolution authorizing a White House subpoena "an unprecedented departure" from the practices of the committee.

"We are entitled to obtain information from the White House to advance our legitimate oversight needs, not for a fishing expedition by the Republicans," Waxman charged, adding that "it's sad to see what's going on today."

"Half a billion dollars of taxpayers' money appears to be lost. This is not a fishing expedition," Stearns responded. "We want answers. … It is unfortunate it has come to this."

Stearns laid out the steps in the committee's investigation of Solyndra leading up to the Nov. 3 vote to subpoena internal White House communications. Earlier this year, he said, the Office of Management and Budget "repeatedly failed to cooperate with our investigation, and we agreed to put off a vote on that subpoena because we were assured that engaging in a dialogue with the administration and the minority would resolve all of the problems without the need to resort to a subpoena."

However, that assurance was little more than a "stalling tactic," Stearns argued. "Unfortunately, the same continued uncooperative conduct by the administration has necessitated today's vote," he said.

On Sept. 1, Stearns noted, the committee asked the White House for all documents containing communications relating to Solyndra between the White House and Solyndra, and between the White House and Solyndra's investors. Select communications produced by the White House revealed that senior advisers in the West Wing were monitoring and discussing Solyndra. "Based on these documents, we sent a second request to the White House Counsel on October 5 for all internal communications relating to Solyndra," he said.

Stearns insisted the committee sought to engage in a dialogue about how best to manage production of documents. However, he said, the White House counsel's office responded in an Oct. 14 letter saying that in the opinion of the White House, the committee did not need to see such documents.

"On October 18, the committee staff informed the counsel's office that it needed to invoke a valid privilege or produce the responsive documents," Stearns said. "When asked again to contact committee staff in order to start a dialogue on this issue, the White House counsel's office refused to engage in any discussion. One week later, on October 25, the White House counsel sent another non-responsive letter to the committee, again refusing to produce the documents, because, in the administration's opinion, the committee did not need to see such documents."

Only after "repeated failed attempts to engage the White House did the committee notify the White House and the administration that it intended to notice a business meeting to discuss the possible issuance of subpoenas to obtain the requested information," Stearns said. "This finally got the attention of the White House counsel and we met with her yesterday."

However, according to Stearns, the White House was unable or unwilling to answer basic questions, including: "Do you have any responsive documents? Are you going to be asserting executive privilege? What quantity of documents do you have? Have you conducted an internal investigation to inform us as to what types of documents you have? Without the answers to these questions, it is nearly impossible to narrow or limit the scope of our requests," the subcommittee chairman said.

Republicans also pointed to recent findings about problems with the loan guarantee program brought to light by DOE Inspector General Gregory Friedman, who testified before the House Oversight and Government Reform Committee's Regulatory Affairs, Stimulus Oversight, and Government Spending Subcommittee on Nov. 2. Friedman said the DOE Loan Guarantee Program office "could not 'readily demonstrate how it resolved or mitigated relevant risks prior to granting loan guarantees,'" Stearns said, adding, "This is extremely troubling."

COMPANY REFERENCED IN THIS ARTICLE:

Solyndra Inc.

Industry Document: Opening Statement of Rep. Henry A. Waxman

Industry Document: Opening Statement of the Honorable Cliff Stearns

E-mail this story.

Amid Solyndra controversy, DOE's Chu rallies for federal support of clean energy

by Jonathan Crawford

Even as the controversy surrounding a federal loan guarantee to the now-bankrupt solar panel maker Solyndra Inc. continues, Energy Secretary Steven Chu, speaking Nov. 3 at a conference on energy policy, rallied behind government support of the clean energy sector, saying that now is not the time to throw in the towel.

"The global competition is fierce, and support for innovative technologies comes with inherent risk. Not every company or every product will succeed, but that is no reason to sit on the sidelines and concede leadership in clean energy," Chu said at a Washington Post Live forum held in Washington, D.C.

Chu, who is slated to testify Nov. 17 before Congress as part of an ongoing investigation into the U.S. Department of Energy's $535 million loan guarantee to Solyndra, cited a number of examples in defending his backing for government support of the clean energy sector. From the domestic aviation and information technology sectors to U.S. auto manufacturing, which was recently on the verge of collapse, government can be critical in promoting and developing industries, he said.

"The lesson from these examples is clear: the U.S. government recognized an economic opportunity, made a choice to compete, and took the necessary actions to promote these industries," he maintained.

Chu said that while solar cells, wind turbines and lithium ion batteries were all invented in the U.S., the nation is no longer a leading manufacturer of any of them. The country has ceded the lead to countries like China, which last year, he said, offered roughly $30 billion in government financing to its solar companies, including $7 billion to Suntech Power Holdings Co. Ltd. Other countries are adopting renewable electricity standards and public financing for clean energy projects, he said.

The U.S., on the other hand, lacks a comprehensive national energy policy and is still debating the economic benefits of the clean energy sector, Chu stated.

© 2011, SNL Financial LC. All Rights Reserved.

Chu said the stakes are large. The global clean energy market is already worth an estimated $240 billion and is growing rapidly, with solar photovoltaic systems alone representing a global market worth more than $80 billion this year.

Responding to questions about the Solyndra controversy, Chu conceded that there is room for improvement for the government program.

"Congress and the administration can design a better loan program. We think we can design a program so that it is self-paid," he said, without elaborating on details.

Chu maintained that such risk-taking is an important part of the nation's narrative, and that the U.S. finds itself at a crossroads of sorts.

"America faces a choice today: Are we going to recognize the opportunity and compete in the clean energy race, or will we wave the white flag and watch all of these jobs go to China, Korea, Germany and other countries?" he said.

COMPANIES REFERENCED IN THIS ARTICLE:

Solyndra Inc.

Suntech Power Holdings Co. Ltd.

✉ E-mail this story.

NH senators see nation's electric reliability declining, seek FERC review

by Kathleen Hart

In the wake of the late October snowstorm that left more than 2 million New Englanders without power, Sens. Jeanne Shaheen, D-N.H., and Kelly Ayotte, R-N.H., wrote to FERC Chairman Jon Wellinghoff on Nov. 3, warning of a decline in reliability and calling for a federal review of reliability standards for America's electric power grid.

"Given your responsibility to protect the bulk electric system and ensure reliability for the millions of consumers and business who rely on electric power, we are requesting your prompt review of the adequacy of our nation's reliability standards," Shaheen and Ayotte wrote in the letter, which was sent to Wellinghoff and North American Electric Reliability Corp. President and CEO Gerry Cauley.

"New Hampshire residents have had to deal with repeated widespread power outages during the past year due to weather-related events, most recently during last weekend's October snowstorm," Ayotte said in a Nov. 3 news release. "With this early record-breaking winter storm serving as a reminder, we must work to ensure proper oversight is in place to guarantee reliability standards."

"While all of us in New Hampshire understand the challenges our weather brings, electric outages seem to be getting worse, not better. We need an electric system we can rely on, one that contributes to our public safety instead of detracting from it," Shaheen said in the news release.

"We are writing regarding the recent snowstorm which has left 315,000 New Hampshire and more than 2 million New England utility customers without power. In New Hampshire alone, the storm caused the loss of ninety-one main circuits, or back bone power lines, for [Public Service Co. of New Hampshire], the largest number in the company's history," the senators wrote. "Three other utilities, [National Grid USA], [Unitil Corp.] and the [New Hampshire Electric Cooperative Inc.] were also heavily affected by the storm."

PSNH is a subsidiary of Northeast Utilities.

Shaheen and Ayotte contended in the letter that electric reliability seems to be declining.

"Perhaps most troubling to us is the seeming downward trend in electric reliability for New Hampshire's utilities. In the case of PSNH, New Hampshire's largest electric utility, during the last two years alone the utility experienced three severe weather incidents which affected hundreds of thousands of electric customers," the letter said. "In addition to last month's snowstorm, which ranks as the third largest power outage in our state's history, 160,000 customers lost power in August of this year from Hurricane Irene and 360,000 customers lost power in February of 2010 from a wind storm. These outages are in addition to three smaller weather-related outages this year which also affected tens of thousands of their customers."

The senators pointed to a study by the Lawrence Berkeley National Laboratory estimating that the national cost of power interruptions is about $80 billion a year.

SNLEnergy POWER DAILY™ The Energy Industry Delivered to You Daily

Published by: SNL Financial LC (ISSN 1556-6943) © 2011

Andrew Engblom, Editor E-mail: aengblom@snl.com Phone: +1.703.373.0168

Michael Lustig, Managing Editor, Energy Group

Mike Chinn, President and CEO • Michael Carter, Director of SNL Energy • Nina Flynn, Subscriptions Manager

Contact information:

Editorial: E-mail: energynews@snl.com Phone: +1.703.373.0150 Fax: +1.703.373.0159

Subscription Support: E-mail: subscriptions@snl.com Phone: +1.434.951.7749 Fax: +1.434.293.0407

Subscription Sales: E-mail: salesdept@snl.com Phone: +1.434.951.7797 Fax: +1.434.817.5330

Advertising: E-mail: sgoldberg@snl.com Phone: +1.434.951.7829 Fax: +1.434.817.5330

SNL Financial • One SNL Plaza PO Box 2124 Charlottesville, VA 22902 • Phone: +1.434.9770.1600 • Fax: +1.434.293.0407

http://www.snl.com feedback@snl.com

© 2011, SNL Financial LC. All Rights Reserved.

"The health and welfare of the American people and the needs of our economy demand a reliable electric power system," the senators added. "Given the most recent events, we think it is incumbent upon the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation to undertake a review of reliability standards."

COMPANIES REFERENCED IN THIS ARTICLE:

National Grid USA
New Hampshire Electric Cooperative Inc.
Northeast Utilities **NU**
Public Service Co. of New Hampshire
Unitil Corp. **UTL**

Industry Document: In Wake of Storm, Shaheen and Ayotte Push for More Oversight of Electric Grid

E-mail this story.

NRG's Crane: Falling cost of solar could revolutionize hub-and-spoke industry model

by Andrew Engblom

The falling price of solar panels could soon revolutionize the traditional hub-and-spoke model of the electric utility industry, eliminating many long high-voltage transmission lines, NRG Energy Inc. President and CEO David Crane said Nov. 3 during an earnings conference call.

"We will be in a situation where within two years the price of delivered power from solar installations will be able to undercut the retail price of grid power in roughly 20 states," Crane said. "Many of these high-price retail states are in our core regions. This low-cost solar power, installed in ever-increasing volumes on a distributed and semi-distributed basis in a way that obviates the need for a lot of very long high-voltage transmission lines, has a potential to revolutionize the hub-and-spoke power system which currently makes up the American power industry."

The delivered cost of solar energy has been cut in half in the past 24 months, Crane said, and he expects that trend to continue.

"Call it, if you will, Crane's Solar Corollary to Moore's law," he said. Other sources of electrical power increase their output by "brute force," but solar energy is essentially a nanotechnology. This makes it more like the semiconductor industry, which has famously doubled the density of transistors, and thus, processor speed, every two years.

"We are convinced that the cost of solar installations is going to continue to drop precipitously, both in absolute terms and relative to other forms of power generation," Crane said. "We believe the delivered cost of energy from solar PV, which has been cut in half in the last 24 months, will be cut again in the next 24 months."

The ramifications of this, Crane said, are that while the solar energy industry historically has largely been a "creature of government financial largess," that this is about to change.

"It's only true if you're looking backwards," Crane said. "If we look forward, we see a solar industry that's going to trend strongly towards distributed and residential installations."

He added that the government should continue to support these sectors, but that the distributed solar market "is a free-market construct."

Strategy to capture this involves distributed projects, retail business

To take advantage of this trend, Crane pointed to NRG's deal with industrial real estate developer ProLogis, which provides NRG with the right of first offer to install solar on rooftops of ProLogis properties in as many as 28 states. Those rooftops could support approximately 733 MW of distributed solar generation opportunities, according to the companies' announcement.

Other plays, Crane said, involve NRG's three retail electricity providers. The company has also made and will continue to make major investments in utility-scale solar projects, Crane said, adding that over time he expects distributed solar to dominate.

"I think that, over time, the distributed residential is going to end up sort of swamping the big-scale projects," Crane said in response to an analyst's question. "We will stay in the utility-side space, but I just wanted to [say] that we're positioning ourselves hard to take advantage of the opportunity we see on the distributing — the residential side."

For the near-term, though, utility-scale projects are the company's biggest solar energy bets, with more than 881 MW of utility-scale solar now under construction or in the final stages of advanced development.

NRG Executive Vice President and COO Mauricio Gutierrez said the 290-MW Agua Caliente solar project is now 40% complete; the 250-MW Colorado Valley Solar Ranch is "up to a good start"; and the first 63-MW unit of Ivanpah is "well under way," with the erection of the first solar receiver tower progressing as planned. Work has also begun on the foundation of the 65-MW unit 2 at the site. Work on the 26-MW Borrego, the 33-MW Alpine and the 25-MW Avra Valley projects is scheduled to begin in the first quarter of 2012. All of these projects are in California except for Avra Valley, which is in Arizona.

The scale of those largest three projects, however, will be difficult to duplicate, Crane said, explaining that they could only be financed due to the federal loan guarantee program that has now expired.

"I am sure there will come a day when we will see another wave of 300-plus megawatt large solar projects, but these projects are more than $1 billion projects, and without federal loan guarantees there is not that much Wall Street money to provide debt on that," Crane said.

As a result, he said he expects utility-scale solar projects to drop back to 20-MW to 100-MW sized deals, which he said NRG will "pursue aggressively."

COMPANY REFERENCED IN THIS ARTICLE:

NRG Energy Inc. **NRG**

PR: NRG Energy, Inc. Reports Third Quarter and Year-to-Date Results and Updated Guidance

Transcript: NRG Energy Inc. (NRG)

Presentation: NRG Energy Inc. (NRG)

E-mail this story.

First Solar expects 'correction' in oversupplied solar panel market

by Andrew Engblom

First Solar Inc. plans to shift its focus toward developing new markets outside of Europe, while slowing its manufacturing expansion as part of a revised strategy following the sudden exit of former CEO Rob Gillette on Oct. 25.

© 2011, SNL Financial LC. All Rights Reserved.



SNL Center for Financial Education

Principles of Valuation in the Power Sector

Hands-on training in the techniques necessary to successfully navigate valuation in the U.S. power sector, whether single assets or whole companies.

December 12–14, Houston, TX

Website: www.snlcenter.com/powerval

Class size is limited – Don't delay.

EASY REGISTRATION

- Online: www.snlcenter.com/powerval
- Phone: (434) 951-7786

PROGRAM FEE

$2,395

WHO BENEFITS

- Finance, investor relations or corporate strategy/corporate development professionals at power or gas companies
- Professionals in investment banking, project finance, asset management, hedge funds, or equity/fixed income research
- Consultants, accountants and lawyers who advise power and gas clients
- Industry regulators
- Current or potential suppliers or professionals looking for an understanding of how Wall Street analyzes the power and gas sector and the fundamentals that bear on their analyses

Program covers

- Identifying the valuation methodologies specific to the U.S. power sector, including DCF, comparables, multiples and real options
- Understanding value drivers, capital structure
- Techniques for acquiring the data used for modeling assumptions
- Valuing single plants, T&D assets, regulated generation assets and whole companies
- Incorporating revenue drivers, including forward and spot pricing, implied heat rates
- Assessing M&A synergies and regulatory considerations
- Understanding the role of power purchase agreements, tolling agreements, steam contracts and other financial arrangements
- Case studies, hands-on modeling and take-away templates

To see the complete agenda, go to www.snlcenter.com/powerval.

Instructor: James W. Bowen

As a veteran consultant in the energy industry, Jim Bowen has successfully valued hundreds of power plants and utilities. Prior to founding his own advisory firm, Momentum Development Corporation, Jim was a consultant with McKinsey & Co. and, previous to that, an attorney with Akin Gump. He holds a J.D., cum laude, from the Harvard Law School, an M.Sc. in Financial Management from the University of London, and a B.S. in Economics from the U.S. Military Academy.

Continuing education credits

This program qualifies for 17 hours professional development credit as granted by CFA Institute and 20.5 hours of CPE credit through the National Association of State Boards of Accountancy. Full details available on the Continuing Education page of the program website.

Register at www.snlcenter.com/powerval

Presented by

SNL Center FOR FINANCIAL EDUCATION

During the company's third-quarter earnings presentation on Nov. 3, First Solar Chairman, founder and interim CEO Mike Ahearn said a new direction was needed given the excess supply of solar panels and declining subsidies in Europe.

"The board felt the leadership change was necessary in order for the company to navigate through the current market conditions," Ahearn said. He also shot down speculation about fraud or major operational actions being related to Gillette's resignation, saying that it was "simply a question of fit."

To move forward, Ahearn said the company must find new customers for its panels and move beyond dependence on the European subsidies. It will also take a bottoms-up approach to rethink how its product is sold and deployed. "We all believe it is economically not feasible to think that this condition can last forever," he said. "There will be a correction is our bet. We need to be very vigilant about how to ride through and build these new markets."

While he declined to lay out a complete new strategy, telling analysts that a review was under way and that more information would be provided next month, he said Europe is not likely to be able to provide substantial new demand in the near future.

"The fact is that today we operate in subsidized markets where the short-term prospects are not as attractive," Ahearn said. "The European countries that subsidized demand that allowed the solar industry to scale to its current levels have been reducing their subsidies. In the U.S., there have been no significant state-level programs in several years, and the solar industry is feeding mostly off of legacy subsidies in California."

Some growth, in the form of utility-scale projects in the U.S., is expected, Ahearn said, but the company will also look to China, India, Australia and Africa for new markets. "We must … go where we can solve pressing problems," he said.

Ahearn said moving beyond the traditional subsidized markets means that the company must overcome the inertia of depending on legacy markets and move off the "short-term fixation" on earnings per share. "These actions will cost money. They will take time," he said. "Our decision-making needs to be guided by creating long-term value."

Vietnam plant postponed

As part of its presentation, Ahearn said the company has postponed plans to bring a new plant online in Vietnam, but that it will go ahead with plans to open a factory in Mesa, Ariz., in order to supply PV modules to its 2.7-GW project pipeline in North America.

Simultaneously, the company announced that it has inaugurated its second manufacturing plant in Frankfurt, Germany. The 50,000-square-meter facility, which reached full production in October, will manufacture 250 MW a year of solar modules. The expansion doubles the company's production capacity in Germany to 500 MW.

Sale of Topaz expected within months

In the U.S., the company closed on the sale of a number of major utility-scale solar projects during the quarter ahead of the sunsetting of the Department of Energy's loan guarantee program. One project, the 550-MW Topaz plant, did not receive a loan guarantee, but First Solar CFO Mark Widmar said the company "is in advanced negotiations with a buyer" and that the sale should be completed "over the next few months."

In other project news, the company said it would build, operate and maintain the 66-MW Alpine solar project in Lancaster, Calif., for NRG Energy Inc.

The company said its average conversion efficiency reached 12.4% for its best manufacturing lines during the third quarter. Its overall average conversion efficiency was 11.8%.

COMPANIES REFERENCED IN THIS ARTICLE:

First Solar Inc.
NRG Energy Inc. **NRG**

PR: First Solar Doubles Production in Germany

PR: First Solar Consolidates Manufacturing, Increases Conversion Efficiency

Presentation: First Solar Inc

E-mail this story.

Progress still targeting year-end closure of merger with Duke

by Amy Poszywak

Progress Energy Inc. Chairman, President and CEO William Johnson said Nov. 3 that the company is still targeting closure of its merger with Duke Energy Corp. by the end of the year, though he acknowledged that the actual closing date will be determined by the timing of regulatory approval at FERC and the state commissions in North and South Carolina.

FERC on Sept. 30 conditioned its approval of the merger on the companies adding more market power mitigation measures. In an Oct. 17 response, Duke and Progress agreed to engage in virtual divestiture, selling the rights to various generating plants' output, and made several additional commitments, such as agreeing to have a market monitor oversee the virtual divestiture process.

FERC has set a 30-day comment period on the companies' response that will run out in mid-November, after which the commission will issue a final decision, Johnson said during the call.

Duke and Progress, despite having already submitted their mitigation plan to FERC, have also asked the agency, in a request for rehearing, why it departed from its precedent when analyzing those competitive impacts.

The South Carolina Public Service Commission, which needs to approve the joint dispatch agreement between Duke and Progress related to the merger, has postponed a hearing on the matter until the week of Dec. 12 in light of the outstanding FERC decision, Johnson said. The North Carolina Utilities Commission is reportedly awaiting FERC's response before making its decision.

COMPANIES REFERENCED IN THIS ARTICLE:

Duke Energy Corp. **DUK**
Progress Energy Inc. **PGN**

Presentation: Progress Energy Inc. (PGN)

E-mail this story.

© 2011, SNL Financial LC. All Rights Reserved.

Duke reveals NC rate case recommendation; future case likely as new plants come online

by Jason Lehmann

Duke Energy Corp. told Wall Street analysts Nov. 3 during a quarterly earnings conference call that North Carolina Utilities Commission staff filed testimony earlier this week on Duke Energy Carolinas LLC's proposed base rate increase, recommending a rate increase well below the company's initial request.

Duke Energy Carolinas in July asked North Carolina regulators to approve a $646 million electric rate increase based on an 11.5% ROE and 53% equity component, effective February 2012. Duke Chairman, President and CEO Jim Rogers said NCUC staff returned with a recommended overall rate increase of $211 million, "reflecting a number of adjustments to cost of service," an ROE of 9.25% and a 50% equity component.

Duke Energy Carolinas also has a base rate increase request pending in South Carolina with the state Public Service Commission, asking for a $216 million rate increase, also based upon an 11.5% ROE and 53% equity component.

Hearings are scheduled to begin Nov. 28 in North Carolina and Dec. 7 in South Carolina on the respective rate increase requests.

"We recognize that rate increases are challenging in these tough economic times," Rogers said. "However, it is very important to remember that these increases are principally the result of investments we have made to modernize our infrastructure and implement federal environmental mandates."

Rogers said Duke "will continue to explore opportunities for settlements in the weeks ahead."

Asked by an analyst if the company is exploring rate impact mitigation measures with North and South Carolina regulators, Rogers acknowledged that Duke "has worked hard in every state" to invest in energy efficiency and to "put control of the use of electricity in the hands of our customers."

That electricity prices are rising due to generating fleet and electric grid investments should come as no surprise, Rogers said.

"Clearly everyone today understands — probably more than they did when we first introduced our energy efficiency measures — the importance of having those in place and giving control to our consumers during this rising price environment," Rogers said.

Duke Group Executive and CFO Lynn Good hinted that as Duke Energy Carolinas' planned 825-MW, coal-fired Cliffside and 620-MW Dan River combined-cycle plants in North Carolina come online in 2012, the company will need an additional rate increase to recover its investment in those facilities.

"We have not estimated an increase at this point," Good said. "I think it will be dependent on the success of this case as well as what we see in terms of our cost structure, so more to come on that."

COMPANIES REFERENCED IN THIS ARTICLE:

Duke Energy Carolinas LLC

Duke Energy Corp. **DUK**

Presentation: Duke Energy Corp (DUK)

E-mail this story.

Progress Energy still addressing challenges at Crystal River 3 nuke

by Amy Poszywak

Progress Energy Inc. Chairman, President and CEO William Johnson on Nov. 3 reaffirmed the company's plans and estimated cost for repairs at its Crystal River 3 nuclear unit in Florida, an issue that has been lingering over the company's share price for quite some time.

"We continue to believe repairing the plant is better for our Florida customers than retiring and replacing it," Johnson said during Progress' third-quarter earnings call. "But as I said in June, we are approaching this situation in a very disciplined structured way and continue to assess cost and feasibility at every step."

The unit has been offline since September 2009 when damage to concrete in the periphery of its containment building was discovered during an attempt to replace steam generators. This "delamination" was followed by the discovery of a second delamination, or separation damage, in March.

In a June 28 conference call, Johnson said the company will spend $900 million to $1.3 billion to repair the Crystal River plant, adding that the cost is well within the plant's $2.25 billion insurance coverage limits. The CEO reiterated that statement during the Nov. 3 call.

In August, the Florida Public Service Commission established a plan to review the prudence and cost related to the Crystal River 3 outage, including replacement power costs, which they then divided into three phases, Johnson said.

"The first phase will focus on the events and decisions leading up to the delamination event on Oct. 2, 2009," Johnson said. "A hearing is scheduled for June 2012 and we filed initial supporting testimony last month. The second phase will review the decision whether to repair rather than decommission the unit. And the third phase will include review of the decisions and events subsequent to the October 2009 event and leading up to the March 2011 delamination and ultimate repair of the containment building."

Johnson said the company has been working closely with Nuclear Electric Insurance Ltd., the insurance company that covers the company against the incremental cost of replacement power resulting from prolonged accidental outages, as it conducts its review of the claim. Crystal River 3 is not expected to be up and running until 2014.

On July 5, Moody's said it expected the delays in the repair plan to have a negative effect on the utility's credit quality and business risk profile but will not immediately lead to a change in the company's credit ratings or rating outlook.

COMPANY REFERENCED IN THIS ARTICLE:

Progress Energy Inc. **PGN**

Presentation: Progress Energy Inc. (PGN)

E-mail this story.

Elster Electricity's Q3 gas gains offset weak North America, Mideast markets

by Dan Testa

German smart metering company Elster Group SE on Nov. 3 reported third-quarter 2011 revenues of $464.4 million, a 2.9% increase over the third quarter of 2010.

© 2011, SNL Financial LC. All Rights Reserved.

Describing it as a "solid quarter," Elster CEO Simon Beresford-Wylie ascribed the gains to a strong gas segment and growing markets in Europe and Latin America overcoming weakness in the water and electricity segments, particularly in North America and the Middle East.

"The strength of Elster's gas business and our geographic diversity have driven our steady performance in the face of the challenging macro environment, especially in North America," Beresford-Wylie said in a news release. "I am very encouraged by our strong forward order book and the momentum coming from Europe and Latin America for their near and mid-term smart grid deployments. I am also especially pleased by the very strong results turned in by our gas business."

Elster's third-quarter 2011 revenue represented a $13.1 million increase over the third quarter in 2011 but a 2.6% decrease on a constant currency basis. Adjusted EBITDA for Elster came in at $67.6 million for the third quarter of 2011, down 10.7% from a year earlier.

GAAP net income from continuing operations attributable to Elster came in at $23.3 million, or 21 cents per American depositary share. Non-GAAP net income was $30.5 million for the third quarter of 2011, down from $43.3 million in the third quarter of 2010.

Elster's gross margin was 31.5% in the third quarter of 2011, compared to 31.2% a year earlier, with the company attributing the solid performance to the gas segment offsetting weaker results in the water segment and North America. Total operating expenses increased by $19 million, or 23.2%, to $100.9 million in the third quarter of 2011, an increase from $81.9 million in the third quarter of 2010.

Elster's gas segment was far and away its strongest performer, with revenues of $276.4 million in the third quarter of 2011, reflecting a 16.7% increase over the prior-year quarter. Profit for the gas segment was $64.1 million for the quarter, an 8.3% increase over the third quarter of 2010. For the first nine months of 2011, gas revenues were $807.2 million, up 18.9% compared to 2010.

Electricity revenues, on the other hand, declined 10.7% from the previous year, to $105.1 million in the third quarter of 2011. Elster's electricity profit of $8.3 million in the third quarter of 2011 marked a 50.9% decrease from the third quarter of 2010.

Elster's water segment fared about the same, with revenues of $91.2 million in the third quarter of 2011, a 10.2% decrease from the year-prior quarter. Water segment profit of $3.5 million amounted to a decline of 62% compared to the third quarter of 2010. Profit margin for Elster's water segment declined to 3.8% from 9.1% in 2010.

In the cases of water and electricity, Elster attributed the declines to sluggish markets in the Middle East and North America.

"In the United States in particular, many customers and prospective customers continue to live in a world of exceptionally tight budgets. The consequences of this, as we have seen throughout the year, are delayed and postponed projects," Beresford-Wylie said on the conference call. "Indeed, the latest third-party industry data points to a contraction in the overall North American region market."

In a report issued later that day, analysts for Macquarie (USA) Equities Research seemed to appreciate the candor of Elster executives in acknowledging a slowdown in metering activity, primarily in North America, the Middle East and Europe. But Macquarie also found Elster "impressively treading water" in the difficult conditions, and it reaffirmed an "outperform" rating for what it described as "the most attractive publicly traded smart metering company."

"Much of our bullish thesis on [Elster] is predicated on its exposure toward the high growth, high margin gas business (including utilization), which limits exposure to the slowdown in US electric metering in particular," Macquarie analyst Andrew Weisel wrote. "Moreover, unlike other metering companies, [Elster]'s customer concentration is extremely low."

Macquarie did, however, lower Elster's target price to $18.50 from $19 and revised non-GAAP EPS estimates for 2012 and 2013 to $1.26 and $1.45, respectively, from $1.28 and $1.49 for the same periods.

Elster's guidance for 2011 was that revenues will grow 5% to 9% for the year, compared to 2010, and the company estimates 2011 GAAP earnings per ADS in the range of 90 cents to $1.

For the first nine months of 2011, Elster reported revenues of $1.4 billion, up $112.4 million, or 8.8%, over the first three quarters of 2010, and up 3.7% on a constant currency basis.

Elster's adjusted EBITDA for the first three quarters of 2011 was $199.7 million, a 3.3% decrease from the $206.6 million recorded in the first nine months of 2010. GAAP net income from continuing operations attributable to Elster over the first three quarters of 2011 was $61.6 million, or 55 cents per ADS. Non-GAAP net income for the first nine months of 2011 was $91.1 million, up 28.1% from $71.1 million in the first three quarters of 2010.

Elster's total operating expenses for the first nine months of the year increased $44.3 million, or 16.1%, to $318.7 million, up from $274.4 million in the same period in 2010. Elster attributed the increased expenses to its transition to a public company, which occurred in the fourth quarter of 2010. The company also incurred a charge of $10.3 million, or 9 cents per ADS, to write off unamortized debt issuance in the second quarter of 2011 from an old credit facility.

COMPANY REFERENCED IN THIS ARTICLE:

Elster Group SE

Industry Document: Elster Reports 2011 Third Quarter and Nine Month Results

Industry Document: Elster Group SE 3Q 2011 Results

E-mail this story.

EPA rules, market factors forcing quick decisions by power plant owners

by Wayne Barber

New clean air rules, renewable standards and the cheap — for now, at least — price of natural gas are forcing power generators to make long-term portfolio decisions in a hurry, speakers said Nov. 3 at the Infocast Power Generation Summit in Washington, D.C.

Tight deadlines in the U.S. Environmental Protection Agency's Cross-State Air Pollution Rule were cited by many speakers, including American Electric Power Co. Inc. Executive Vice President of Generation Mark McCullough.

"Let's take a little moment here," McCullough said. "We are not out to gut the Clean Air Act." But big generators such as AEP want enough time to do environmental retrofits on coal plants while replacing the weakest coal units by building natural gas-fired plants, he said.

AEP is looking to retire 6,000 MW of older coal units by 2015. That is a concern because these units are still used a lot during heat waves, McCullough said. Given the time that it takes to build either

© 2011, SNL Financial LC. All Rights Reserved.

a new gas plant or an SO2 scrubber, the current CSAPR time frames are not feasible, he said.

When asked why AEP had not been retrofitting more coal units before the cross-state rule was published, McCullough said AEP has spent millions of dollars studying how to comply with previous EPA rules only to see them thrown out by the courts a couple of years ago.

The timing of the EPA deadlines "limits your options," said Kimberly Malm Adelberg, a climate strategy manager with a Southern Co. subsidiary.

Various speakers also predicted that the cross-state rule, coupled with other EPA proposals on everything from regional haze to cooling water, could shrink reserve margins in many regions of the country.

"We don't know if we will have adequate generation" if the cross-state rule goes into effect in January 2012, said Donna Nelson, who chairs the Public Utility Commission of Texas. Generators in Texas have sued the EPA over a decision to include Texas in the cross-state rule, and Nelson admitted that Texas has not yet formulated much of a "Plan B."

Some speakers noted that generators in regulated states can at least pass on the cost of complying with EPA rules to ratepayers. But Pennsylvania Public Utility Commission Chairman Robert Powelson predicted that such requests will yield "regulatory fatigue" at state commissions that must deal with ratepayers.

Consultant takes contrary view on natural gas

Most power generators — both regulated utilities and independent power producers — have turned to new natural gas plants as their default source of generation. But Stuart Pearman, a partner with ScottMadden Inc., cautioned that the electricity sector has seen such "silver bullets" in the past and they often misfire.

"Gas is the silver bullet right now. Everybody knows that except for me," Pearman said. He likened it to an imbalanced stock portfolio. "What we like to do in this industry is just buy one stock," he said.

The power industry has seen a dash to gas in the past, and it resulted in an overbuild of natural gas-fired plants, Pearman said. The shale gas revolution could turn out to be more complicated than many expect, he cautioned. A company that develops natural gas reserves assuming the price will be $5.10 per Mcf will be hurting if the market price turns out to be much less, he said.

As for other options, Pearman said the Fukushima Dai-ichi nuclear disaster in Japan has eliminated the chances for any "grand bargain" on Capitol Hill to provide incentives for both nuclear power and renewable energy.

CPS Energy President and CEO Doyle Beneby said that the San Antonio municipal utility has to be more "defensive" than many of its investor-owned counterparts. This means hedging its bets between traditional power plants and more renewable energy, he said.

COMPANIES REFERENCED IN THIS ARTICLE:

American Electric Power Co. Inc.	AEP
CPS Energy	
Southern Co.	SO

Presentation: American Electric Power Co. (AEP)

E-mail this story.

With multitiered strategy, Edison keeps eye on EMG prize

by Jason Lehmann

Though Edison International plans no new equity investments in its competitive generation subsidiary, Edison Mission Group Inc., it has outlined several "potential scenarios that can produce real value at EMG," according to Chairman, President and CEO Ted Craver.

"The size of that potential value seems large enough to us to warrant pursuing," Craver said Nov. 2 during a quarterly earnings conference call with Wall Street analysts. "However, we also recognize that there is not unlimited time to work the many scenarios. We are approaching the time when scenarios will give way to decisions and we believe many of these will be made over the next six to 12 months."

Craver said the U.S. Environmental Protection Agency's final Mercury and Air Toxics Standards Rule scheduled to be finalized in December will allow EMG subsidiary Midwest Generation EME LLC to crystallize its emissions compliance strategy and to begin making decisions on individual plant retrofits, though other EPA proposals surrounding greenhouse gases and water will also play into those decisions.

At Midwest Generation, Craver said, EMG will only make emissions retrofits "where it can see sustainable value for making those investments," and is fine-tuning its construction timeline to meet its emissions reduction obligations while simultaneously minimizing major capital spending into 2012 and complying with construction permits for its coal-fired Waukegan and Powerton generating plants in Illinois.

Second, Craver said that because Edison will not commit equity financing, EME Homer City Generation LP must gauge its ability to secure third-party financing for its planned installation of flue gas desulfurization scrubbers on Homer City units 1 and 2. EMG will consider project sales as an option to meet its liquidity needs, but Craver said realized prices in the PJM Interconnection LLC capacity auction for the 2015-2016 capacity auction will be "a critical indicator of future value for our fleet."

"One would think that the shut down decisions by other generators since the last auction should lead to a further improvement in capacity prices but this needs to be confirmed," he said.

EMG is also evaluating Homer City's compliance with the EPA's phase one Cross-State Air Pollution rules in 2012-2013 "taking into account PJM rules, existing capacity sales and allowance price and availability."

EMG also needs to establish "a more sustainable capital structure," which Craver said will require winding down about $1 billion of the merchant's $3.7 billion of outstanding unsecured debt.

Generation beyond coal

Of EMG's 2,000-MW wind portfolio under construction and in development, the company is seeking financing for 1,042 MW of wind development, including nonrecourse debt financings for its contracted projects.

"As many of you are aware, the project finance market has tightened with the ongoing European banking situation and we are exploring the private placement market as an alternative to the project finance market," Edison CFO, Treasurer and Executive Vice President W. James Scilacci said, later adding that "our job here is to look to see if we can finance the maximum extent possible or find PPAs for those emerging projects and then flip them into potential project financings."

© 2011, SNL Financial LC. All Rights Reserved.

According to the company's CapEx forecast, renewable capital and construction spending will total $274 million in 2011 and $108 million in 2012.

COMPANIES REFERENCED IN THIS ARTICLE:

Edison International **EIX**

Edison Mission Group Inc.

EME Homer City Generation LP

Midwest Generation EME LLC

Presentation: Edison International (EIX)

Transcript: Edison International (EIX)

E-mail this story.

Black & Veatch: Utilities face tough coal retirement decisions

by Matthew Bandyk

While the U.S. Environmental Protection Agency's proposed emissions standards for coal and oil-fired power plants may get delayed again, numerous utilities are feeling pressure to make decisions as soon as possible to either retire or retrofit aging coal plants, according to Black & Veatch Corp. Management Consulting Managing Director Robert Patrylak.

Several of the utility clients that Patrylak works with as part of Black & Veatch's strategic resource planning service line have expressed concern that in the next few months they will have to begin the actions needed to comply with the EPA regulations, he said in a Nov. 1 interview. Even immediate action could be too late. "They are concerned that even if they make the decision now, they're not going to have time to meet the regulations," he said.

Because of the short timeframe, for some plant owners, future delays of the regulations may be rendered moot because they will have already taken action by the time a delay is implemented. "If they've already made the decision to go forward, then you would have already gone down the road of spending that money," Patrylak said.

Black & Veatch periodically publishes forecasts for the U.S. power generation sector. In its most recent analysis, released last spring, the firm found that 64 GW of coal-fired capacity will be retired by 2020, and the main drivers of these retirements will be the EPA's Cross-State Air Pollution Rule, the Mercury and Air Toxics Standards Rule and federal regional haze regulations.

The analysis attempts to model on a unit-by-unit level, based on the costs of regulations and the capacity revenue in regional markets, at what point it will be economic for a utility to retire a plant rather than retrofit it with controls to comply with regulations.

The results, outlined in a presentation that Patrylak gave Nov. 2 at the Infocast Power Generation Summit in Washington, D.C., found that 46% of the retirements are in the Midwest region, with 31% in the Southeast, 16% in the West, and 7% in the Northeast.

Texas, which the analysis counted as its own region, saw no retirements. "Gas is typically on the margin," Patrylak said. In Texas, "there's more profit margin between the costs of the coal, so we're not seeing much of an impact" in the Electric Reliability Council of Texas Inc. market, he said.

Black & Veatch is working on an update of this analysis to be released the first week of December. Patrylak said that based on his preliminary review of the numbers, he expects the new analysis will have similar findings for Texas as the spring analysis.

The potential impact of greenhouse gas regulation was also included in the firm's forecasts. The spring analysis assumed that the federal government would impose a cap-and-trade program starting in 2035. This program was found to have the most powerful retirement effect on plants that are between baseload and peaking status.

"Introducing greenhouse gas [regulation] can actually change the whole perspective for a lot of mid-merit assets," Patrylak said at the conference. "That increased cost eats right into the margin and causes the plant to operate less as the coal cost gets more parity with the natural gas asset."

All told, the Black & Veatch analysis found that conventional coal-fired generation would fall from 31% of the nation's electric generation capacity mix today to 15% in 2035. Combined-cycle gas-fired generation, meanwhile, will increase from 21% to 30% of the capacity and renewables will grow from 6% to 16%, according to the analysis.

COMPANIES REFERENCED IN THIS ARTICLE:

Black & Veatch Corp.

Electric Reliability Council of Texas Inc

Presentation: Black & Veatch Corporation

E-mail this story.

Ormat eyes future geothermal development

by Matthew Bandyk

Ormat Technologies Inc. has 160 to 165 MW of new geothermal projects or expansions under construction, company executives said Nov. 3.

One of the largest is the 30-MW first phase of the McGinness Hills project in Lander County, Nev. According to a presentation that accompanied the company's third-quarter earnings call, field development and construction of the project is in progress, and the Ormat Industries Ltd. subsidiary expects it to be completed in 2012.

McGinness Hills, as well as two other Ormat projects, recently received a loan guarantee for up to $350 million from the U.S. Department of Energy.

"The nominal interest on the part of the loan that was funded earlier this week is an exceptionally low 4.687%, and this will reduce our interest rate over the long term," Ormat Technologies CEO Dita Bronicki said during the call.

The 160 to 165 MW of projects under construction include a 36-MW plant in Kenya. Of the seven U.S. projects, Ormat expects all but one to qualify for the Section 1603 investment tax credit cash grant program. However, the investment tax credit status of the company's proposed 20-MW Carson Lake plant is uncertain. "We are developing a new project schedule to determine if the project can still meet the ITC deadline," President and COO Yoram Bronicki said during the call.

The company also has 123 MW of projects in early development. Of those, the two U.S. projects are the 15-MW Crump Geyser project in Oregon, with commercial operation expected in 2013, and the 30-MW Wister Phase I in California, which does not have an announced operation date.

The company also is exploring 31 sites in Oregon, Idaho, Nevada, Utah, California, Alaska and Hawaii for potential development of new facilities.

On Nov. 2, Ormat reported third-quarter adjusted EBITDA of $46.7 million, compared to $78.8 million in the third quarter of 2010.

© 2011, SNL Financial LC. All Rights Reserved.

For the quarter, revenues from the company's electricity segment were up to $86.8 million from $83.4 million a year earlier. The presentation attributed the increase mostly to higher electricity rates for plants such as the 31-MW Puna Geothermal Venture I project in Hawaii. Ormat is planning an 8-MW expansion of the plant.

"Puna enhancement has been completed and we are ready to deliver power to the grid as soon as the [power purchase agreement] is approved" by the Hawaii Public Utilities Commission, Yoram Bronicki said.

COMPANIES REFERENCED IN THIS ARTICLE:

Ormat Industries Ltd.
Ormat Technologies Inc. **ORA**

Presentation: Ormat Technologies Inc. (ORA)

E-mail this story.

Enbridge to acquire 50% stake in 300-MW Quebec wind project

by Wijdan Khaliq

Enbridge Inc. and EDF EN Canada Inc. signed an agreement under which Enbridge will invest C$330 million to acquire a 50% interest in the 300-MW Lac Alfred Wind Project in Quebec.

The wind project will consist of 150 turbines supplied by REpower systems AG. Construction of the project is slated to take place in two phases. Phase one began in June and is expected to be finished in December 2012, while phase two is expected to be completed in December 2013, according to a Nov. 3 news release.

EDF EN Canada will continue to lead and manage the construction phase under a fixed-price, turnkey engineering, procurement and construction agreement. The company's operation and maintenance affiliate, enXco Service Canada, will provide long-term operations and maintenance services.

The project will sell its power under a 20-year power purchase agreement to Hydro-Québec, which will also construct a 30-kilometer transmission line to connect the project to the grid under an interconnection agreement.

The transaction is subject to customary conditions precedent, including the consent and approval of Hydro-Québec Distribution and Hydro-Québec TransEnergie, according to the release.

EDF EN Canada is a subsidiary of EdF Energies Nouvelles, which is in turn a subsidiary of EDF Group.

COMPANIES REFERENCED IN THIS ARTICLE:

EDF EN Canada
EdF Energies Nouvelles
EDF Group
Enbridge Inc. **ENB**
Enxco Service Canada
Hydro-Québec
REpower systems AG

PR: EDF EN Canada Inc. and Enbridge Partner in the 300-MW Lac Alfred Wind Project in Quebec

E-mail this story.

FERC allows PJM to shorten waiting period for board members

by Glen Boshart

FERC on Nov. 1 approved a PJM Interconnection LLC proposal to shorten the period of time that a former director, officer or employee of a PJM member or a member's affiliate must be removed from that position before being elected to PJM's board.

In asking FERC to reduce the waiting period to two years, PJM explained that the existing five-year waiting period has been hampering its ability to find qualified board members, i.e., those with experience dealing with industry issues specific to the region.

"It is beneficial and crucial to PJM's continued success that the board attract members from the PJM region who are familiar with the current practices and operations of PJM," the RTO told FERC. "By electing members to the board from the PJM footprint, PJM will be able to maximize local input, rather than expend time and resources seeking and training candidates who lack the PJM-specific expertise that adds significant value to the PJM board."

PJM said its ability to find qualified candidates residing in its footprint has become increasingly difficult as its membership ranks have exploded to 727 members. Expecting that growth to continue, PJM said the five-year waiting period has made recruiting even more difficult. The proposed two-year waiting period would reduce at least this hurdle, PJM explained.

As for any independence concerns, PJM insisted that requiring nominated candidates to be two years removed from any position they may have had with PJM members or affiliates will still ensure the RTO's independence, while allowing PJM to access people with current, region specific expertise.

The RTO also told FERC that its proposed waiting period is "already common practice in the industry," noting that three other ISOs require no waiting period while the rest mandate a two-year waiting period. Moreover, citing a 2004 federal appeals court ruling in a case involving the California ISO, PJM reminded FERC that court precedent holds that the agency must give deference to RTOs and ISOs regarding governance decisions.

PJM asked that the proposed changes to its operating agreement become effective Nov. 22.

Noting that no party opposed PJM's proposal, FERC approved it without comment through a designated letter order. (ER11-4630)

COMPANY REFERENCED IN THIS ARTICLE:

PJM Interconnection LLC

Regulatory Filing: PJM

Regulatory Filing: PJM

E-mail this story.

© 2011, SNL Financial LC. All Rights Reserved.

Edwardsport *continued*

Buck, the roughly $700 million project is on budget. Duke said it has spent $375 million on the plant through Sept. 30.

Duke's most controversial project, the 618-MW integrated gasification combined-cycle Edwardsport facility in Knox County, Ind., is 96% complete, with about $2.93 billion invested in the plant, which Duke now estimates will run about $3.3 billion. The proposed cost cap to customers remains at $2.72 billion for construction costs.

Duke still expects that the plant will be in service in fall 2012, but the company is awaiting an Indiana Utility Regulatory Commission decision on whether Duke can recoup the $2.72 billion proposed cost cap from customers and whether intervenor allegations that Duke fraudulently concealed or grossly mismanaged the project are true.

"Our case is supported by independent auditor testimony demonstrating the costs of the Edwardsport plant were both reasonable and necessary and that we prudently managed the project," Duke Chairman, President and CEO Jim Rogers said during a Nov. 3 earnings conference call. "Our testimony in … early September demonstrates that the intervenors' allegations are unfounded."

Rogers said extensive startup testing is under way at Edwardsport, and mechanical and electrical systems will be turned over to startup crews later this year.

"The plant, which will use Indiana coal, will provide cleaner, more efficient energy to our customers in the state," he said. "Due to its efficiency and low cost of energy, Edwardsport will be the first plant to be dispatched on our Indiana system and remains the best solution for our customers' needs, helping to ensure the energy future of this region."

Completion of the projects will allow Duke to continue retiring older, inefficient generation the company has deemed too costly or unpractical to fit with emissions controls.

"When our modernization program is complete, nearly 100% of our coal generation capacity will have scrubbers in operation. This positions us well as the EPA continues to finalize more stringent environmental regulations," Rogers said. "At this time our current plans for compliance assume we have already retired or will retire almost 3,800 MW of coal generation, or about 20%, of our existing coal fleet system wide by 2015."

Renewable build-out also on track

Duke also expects to wrap about 800 MW of wind projects in 2012, bringing Duke's wind portfolio to about 1,800 MW when completed. "Consistent with our strategy, each of these projects is backed by long-term power purchase agreements," Rogers said.

Plants slated for completion in 2012 include the Los Vientos phase 1 and 2 facilitates in Willacy County, Texas, totaling 402 MW; the 168-MW Ironwood project in Ford County, Texas; the 131-MW Cimarron Wind plant in Gray County, Kan.; and the 69-MW Laurel Hill facility in Lycoming County, Pa.

COMPANIES REFERENCED IN THIS ARTICLE:

Duke Energy Carolinas LLC

Duke Energy Corp. **DUK**

Presentation: Duke Energy Corp (DUK)

Transcript: Duke Energy Corp (DUK)

E-mail this story.

Calif. electric utilities *continued*

points from currently allowed water ROEs. "When you move from 10.2% to 10% ROE, it has an almost meaningless impact," Storozynski said. "That is why I think it is positive."

PG&E Corp. subsidiary Pacific Gas and Electric Co. and Edison International subsidiary Southern California Edison Co. are expected to begin their cost-of-capital reviews sometime in 2012, the report said.

"Over the last couple of decades, and especially since the electric deregulation in the state, electric utility ROEs in California have been much higher than those for water and gas utilities due to higher levels of capital spending and high debt imputed from power purchase agreements for California electrics," the report said. "We believe the ROE premium for electrics over water should continue especially as [PG&E Corp.] and [Edison International] have signed numerous new conventional and renewable [power purchase agreements] since their ROEs were last set, further increasing their debt levels imputed by credit agencies."

The 2013 earnings-per-share estimates for both electric companies could rise from current levels. The current levels reflect a 100-basis-point reduction in allowed ROEs, so there is room for ROE increases, the report said.

"The companies should see an above average EPS growth driven by [capital expenditures] and regulatory recovery, and yet [they] three trade at a significant [price-to-earnings ratio] discount to their peers," the report concluded.

DRA: Cost of capital decreasing

Division of Ratepayer Advocates Director Joe Como said in an interview that the assumption should not be made that his division will settle for higher ROEs for the electric companies. He said the investor-owned electric utilities are already earning ROEs that are higher than they should be.

"Return on equity should follow the cost of capital, and the cost of capital has been decreasing, not increasing," Como said. "We have always argued the return on equity has been too high, higher than it needs to be. They should get a fair return on their equity but not higher than reasonable. The value of that equity has come down, and their ability to get capital is cheaper, so they should pass some of that cost savings on to ratepayers."

ROEs should not be higher than absolutely necessary, he said, because the state has spent so much on renewable energy resources to achieve its environmental objectives, and renewables are much more expensive than traditional resources and thus impact ratepayers.

"We cannot expect the customers to be saddled with any unnecessary cost, and it is unnecessary to pay too much on return on equity," he said. "I believe the energy utilities need to reduce their return on equity as well."

The utilities are making more money because of the high price of renewables and the state's renewable standard goals, and they are doing so comfortably as natural monopolies, Como concluded.

In California, the ROE levels are set in the midcycle of general rate cases, Como said. He said he expects that the utilities will make their ROE filings around March 2012, and the proceedings would continue through the rest of the year, so any changes in the cost of capital for the electric utilities would not take effect until 2013 at the earliest.

PG&E, SoCalEd assess earnings

Edison International and PG&E released their third-quarter earnings Nov. 2 and 3, respectively. PG&E Corp. Chairman, President and

© 2011, SNL Financial LC. All Rights Reserved.

CEO Anthony Earley Jr. said in a Nov. 3 earnings call that the company has determined that it needs to spend more on its gas and electric systems. The company will spend about $200 million more than it previously planned in 2012 and about the same amount again in 2013 to improve safety and reliability of operations across the utility, but mostly on the gas side.

The company's response to the San Bruno, Calif., gas pipeline explosion in September 2010 will have a negative impact on the company's earnings in 2012, which will continue into 2013, Earley said. "It is our objective, however, to earn our authorized return in 2014. Some of this additional spending will be acceleration of work we'd previously planned to complete over a longer period," he said.

Meanwhile, in a Nov. 2 earnings call, Edison International CFO, Treasurer and Executive Vice President W. James Scilacci Jr. said the company's ongoing message is that rate-based growth will increase regulated subsidiary SoCalEd's earnings, while lower gross margins for the merchant coal fleet have and will adversely impact subsidiary Edison Mission Energy's earnings.

During the call, an analyst noted that the midpoint earnings estimate of $3.15 for SoCalEd "on its face appears to be an ROE modestly in excess of the 11.5," though he said this probably includes construction work in progress and takes into consideration how corporate allocations "move around."

Scilacci replied that his company has benefited from tax benefits and "a lot of cash" that has deferred the need to finance as much as originally forecast, resulting in lower interest expense. SoCalEd CFO and Senior Vice President Linda Sullivan also said the timing of the company's capital spending program was a factor.

Later, Scilacci declined to speculate on a question about whether the ROE for FERC-jurisdictional transmission operations would be more or less than 11.1% beyond 2012. "It's going to be in the general ballpark and it has a small impact … because when you look at the total rate base, FERC is 15% of our total rate base so it's going to be small impacts if it's changing 5 or 10 basis points," he said.

SoCalEd's 2012 general rate case is moving into its final stages, Edison International Chairman, President and CEO Theodore Craver Jr. said. The last major procedural filings were made in October and the record is now basically complete, he said, adding that the assigned administrative law judge must now draft a proposed decision, and the PUC is scheduled to decide the case by the end of the year. If the final decision is delayed, the commission has already ruled that the new rates will be retroactive to Jan. 1, 2012, Craver said.

COMPANIES REFERENCED IN THIS ARTICLE:

Edison International	EIX
Edison Mission Energy	
Pacific Gas and Electric Co.	
PG&E Corp.	PCG
Southern California Edison Co.	

Transcript: Edison International (EIX)

Transcript: PG&E Corp. (PCG)

Regulatory Filing: Golden State Water Co

E-mail this story.

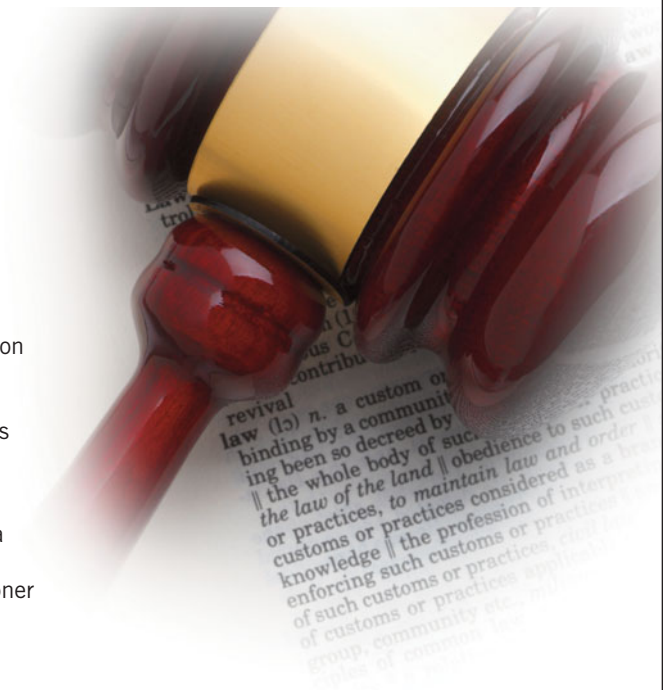
RRA. The presiding authority on utilities
regulation.



From the latest rate case rulings to commission profiles with rankings, RRA (Regulatory Research Associates, an SNL company) has been the leading authority on utility securities and regulation for 30 years.

See real-time news or review 30 years of archived rate case analysis. Get hard-to-find data such as Allowed Return on Equity or Authorized Rate Base. Customize aggregated rate case data screens. Compare commissioner profiles and regulatory topics across several jurisdictions with one-click ease.

RRA gives you the regulatory news and insight you need to make smart energy investment decisions.



SNLEnergy 866.296.3743 • inquiry@snl.com • www.SNLEnergy.com
Your single source for energy intelligence.

© 2011, SNL Financial LC. All Rights Reserved.

Market Story

Next-day power prices end mixed, caught between generally weaker demand, rising gas

by Amanda Luhavalja

Spot power markets saw choppy action Thursday, Nov. 3, with generally lower demand outlooks ahead of the approaching weekend running counter to rising gas prices and ongoing unit outages across the country. Next-day power markets advanced in Texas and parts of the Northeast and Midwest, with spot values ending flat to down across much of the West as traders worked a partial weekend product.

Looking at natural gas, following a 3.2-cent loss Nov. 2, the December gas futures contract rebounded to the upside Thursday, settling the day at $3.778/MMBtu, up 2.9 cents even after the U.S. Energy Information Administration reported at midmorning a larger-than-expected 78-Bcf injection into storage for the week ended Oct. 28.

With the rebound in futures, physical gas prices were swept higher, suggesting rising fueling costs for U.S. power generators. According to data from IIR Energy, almost 100,000 MW is offline across the U.S., up almost 18,000 MW on the day with almost half of the outages located along the East Coast.

IIR data shows a large portion of the downed units, more than 42,500 MW, is coal-fired, up about 6,500 MW on the day. In terms of nuclear supply, SNL Energy data shows total U.S. nuclear supply remains below 85% capacity.

Texas prices move higher with expected ramp in demand, rise in spot gas

Spot power prices in Texas ratcheted higher Thursday, as rising spot gas prices and an expected bump higher in demand come Friday supported gains.

At the spot markets, ERCOT North, South and Houston power parcels were exchanged in the low $30s, gaining $2 to $3 on average on the session.

The ERCOT grid operator sees demand peaking at 40,184 MW on Friday, up about 8,000 MW from Thursday.

Northeast power markets see choppy moves

With milder temperatures in the 60s and 70s in areas across the region expected to keep a lid on demand ahead of the weekend, running counter to stronger physical gas markets, spot power prices in the Northeast chopped around Thursday.

In New England, at the NEPOOL-Mass hub, spot on-peak power was transacted in the low $40s, up 50 cents on the day, with the off-peak market pegged in the mid-$30s. In New York, at the Zone G hub in the east, next-day parcels were reported done in the low $40s, down about 75 cents. To the south, in the mid-Atlantic, next-day deals at the PJM West hub were inked in the low $40s, down almost $5 on the session.

Demand in the PJM Mid-Atlantic region is seen cresting near 32,243 MW on Friday, decreasing about 1,400 MW from Thursday, while in the PJM Western region, load is expected to peak near 44,781 MW on Friday, down about 900 MW from Thursday.

In the north, New England demand is seen peaking near 16,130 MW on Friday, down more than 500 MW from Thursday, while New York load is expected to reach a high of 18,963 MW on Friday, dropping more than 1,000 MW from Thursday.

Midwest power prices run mixed amid lower demand outlooks, rising gas

Next-day power markets in the central U.S. saw a mixed session Thursday as higher spot gas prices were offset by weaker demand projections for Friday.

In Ohio, at the Cinergy hub, spot on-peak power parcels traded in the mid-$30s, easing about $1 on the day, and off-peak deals were done in the mid-$20s. Spot peak power at the PJM AEP Dayton hub was transacted in the high $30s, down $2.50 in value.

Demand in the AEP region in Ohio is seen cresting near 15,890 MW on Friday, down about 800 MW from Thursday, while load in ComEd is expected to peak near 11,761 MW on Friday, easing about 850 MW from Thursday.

Most West Coast markets firm to lower with partial weekend inclusion

West Coast power prices were generally flat to lower Thursday, as traders worked a revised lower-load Friday-Saturday product ahead of the upcoming weekend, which deflated values.

Load in California is projected to peak near 29,100 MW on Friday, down about 300 MW from Thursday before falling even further Nov. 5.

In California, spot heavy-load power at North Path-15 was exchanged in the low $40s, flat on the session. Heavy-load parcels at South Path-15 ran in the upper $30s, down more than $2 on the session.

In the Northwest, heavy-load deals at Mid-Columbia were dealt in the mid-$30s to low $40s, flat on the day, with heavy-load packages at COB done in the upper $30s to low $40s, up nearly $2.

In forward trading at Mid-C, trading was thin. "We saw a few term trades today," according to a trading source. December delivery deals were pegged near $36.75, with January 2012 parcels assessed at $33.25 and third-quarter 2012 business done at $37.

Spot heavy-load power at Palo Verde and Mead in the Southwest was transacted in the mid-$20s, easing more than $3 on the day at the two markets. Light-load power packages at Palo Verde and Mead ran in the mid-$20s.

© 2011, SNL Financial LC. All Rights Reserved.

Energy Pricing Trends

Peak Electricity Index (Day Ahead prices for Delivery on Nov 04, 11)

Delivery Point	Volume Wgtd. Average ($/MWh)	Change From Nov 03, 11 ($/MWh)	Volume Wgtd. Average %△ 1 Day	Volume Wgtd. Average %△ 1 Year	Trade ($/MWh) Median	Trade ($/MWh) Low	Trade ($/MWh) High	Trading Volume (MWh)	All Peak Hours Volume (MWh)
MIDWEST									
A.D.	39.50	-2.50	-5.95	3.95	-	-	-	-	-
Cinergy	35.50	-1.25	-3.40	4.41	35.63	35.25	36.00	150	2,400
Michigan	34.00	-3.00	-8.11	-6.85	-	-	-	-	-
Minnesota	29.25	1.25	4.46	-8.59	-	-	-	-	-
N. Illinois (CE)	33.00	-1.50	-4.35	-6.38	-	-	-	-	-
NORTHEAST									
NY Zone A	36.25	0.25	0.69	2.11	-	-	-	-	-
NY Zone G	43.00	2.00	4.88	-9.47	-	-	-	-	-
NY Zone J	46.00	1.50	3.37	-8.46	-	-	-	-	-
Nepool-Mass	42.75	0.50	1.18	-4.47	-	-	-	-	-
Ontario	31.75	0.75	2.42	-2.31	-	-	-	-	-
PJM West	39.88	-4.91	-10.96	-11.63	40.00	39.25	41.50	300	4,800
OTC BROKER									
Broker ERCOT-Hou.	32.83	2.58	8.53	16.54	32.75	32.50	33.00	150	2,400
Broker ERCOT-North	32.77	2.59	8.58	19.55	32.88	32.50	33.00	600	9,600
Broker ERCOT-S.C.	-	-	-	-	-	-	-	-	-
Broker ERCOT-South	32.50	1.50	4.84	15.86	32.50	32.50	32.50	300	4,800
Broker ERCOT-West	31.25	3.25	11.61	25.00	-	-	-	-	-
SOUTH									
ERCOT-Hou.	33.00	2.75	9.09	17.15	33.00	33.00	33.00	200	3,200
ERCOT-North	33.00	2.82	9.34	21.59	33.00	32.75	33.00	850	13,600
ERCOT-NE	-	-	-	-	-	-	-	-	-
ERCOT-S.C.	-	-	-	-	-	-	-	-	-
ERCOT-South	32.75	1.87	6.06	15.32	32.75	32.75	32.75	150	2,400
ERCOT-West	31.25	3.25	11.61	25.00	-	-	-	-	-
Entergy	33.75	0.25	0.75	8.87	-	-	-	-	-
Fla. In-State	32.00	-5.50	-14.67	-33.68	-	-	-	-	-
Fla.-Ga. Bdr.	31.50	-5.25	-14.29	-12.50	-	-	-	-	-
Southern	32.50	-1.50	-4.41	-4.41	-	-	-	-	-
WEST									
COB	39.50	0.75	1.94	21.54	39.50	39.50	39.50	25	400
Mead	34.25	-3.50	-9.27	3.79	-	-	-	-	-
Mid-C	36.33	0.08	0.22	24.63	36.50	35.25	36.50	175	2,800
NP-15	41.00	0.00	0.00	6.49	-	-	-	-	-
Palo Verde	34.80	-2.95	-7.81	10.06	35.00	34.50	35.00	125	2,000
SP-15	36.50	-2.50	-6.41	-2.67	-	-	-	-	-

Off-Peak Electricity Index (Day Ahead prices for Delivery on Nov 04, 11)

Delivery Point	Volume Wgtd. Average ($/MWh)	Change From Nov 03, 11 ($/MWh)	Volume Wgtd. Average %△ 1 Day	Volume Wgtd. Average %△ 1 Year	Trade ($/MWh) Median	Trade ($/MWh) Low	Trade ($/MWh) High	Trading Volume (MWh)
MIDWEST								
Cinergy	26.00	0.50	1.96	-	26.00	26.00	26.00	200
OTC BROKER								
Broker ERCOT-Hou.	24.60	2.60	11.82	34.79	24.75	24.50	25.00	250
Broker ERCOT-North	25.15	2.88	12.93	39.72	25.00	25.00	26.00	1,300
SOUTH								
ERCOT-Hou.	24.88	2.88	13.09	29.65	24.88	24.75	25.00	100
ERCOT-North	25.29	3.00	13.46	35.68	25.38	25.00	26.00	1,000

© 2011, SNL Financial LC. All Rights Reserved.

Energy Pricing Trends *continued*

Gas Index (Day Ahead prices for Delivery on Nov 04, 11)

Trading Hub	Volume Wgtd. Average ($/mmBtu)	Change From Nov 03, 11 ($/mmBtu)	Volume Wgtd. Average %△ 1 Day	Volume Wgtd. Average %△ 1 Year	Trade ($/mmBtu) Median	Trade ($/mmBtu) Low	Trade ($/mmBtu) High	Trading Volume (mmBtu)
GULF COAST								
ANR-Patterson (LA)	3.372	0.094	2.87	0.36	3.377	3.320	3.380	64,800
Agua Dulce	3.370	0.045	1.35	0.60	3.370	3.370	3.370	5,000
Carthage	3.323	0.116	3.62	1.93	3.330	3.250	3.360	16,200
Col Gulf Mainline	3.358	0.073	2.22	0.63	3.383	3.290	3.440	398,683
Col Gulf Onshore	3.375	0.080	2.43	0.72	3.380	3.335	3.410	74,900
FGT Zone 2	3.370	-0.010	-0.30	0.90	3.370	3.370	3.370	12,000
FGT Zone 3	3.477	0.020	0.58	1.13	3.465	3.350	3.580	88,400
FGT Zone 1	3.360	-0.010	-0.30	0.00	-	-	-	-
Henry Hub	3.372	-0.029	-0.85	0.75	3.372	3.360	3.435	78,000
Houston Ship Channel	3.347	0.034	1.03	1.73	3.365	3.280	3.420	90,700
Katy	3.319	-0.008	-0.24	-0.12	3.320	3.280	3.400	263,100
Moss Bluff	3.450	0.090	2.68	1.98	3.450	3.450	3.450	1,700
NGPL Gulf Line	3.370	0.050	1.51	1.20	-	-	-	-
NGPL Louisiana	3.340	0.040	1.21	2.45	-	-	-	-
NGPL South TX	3.353	0.056	1.70	1.30	3.348	3.285	3.370	34,000
Sonat	3.452	0.085	2.52	2.49	3.450	3.430	3.465	165,200
Stingray	3.460	0.050	1.47	-0.29	-	-	-	-
TETCO M2	3.525	0.125	3.68	-2.62	3.610	3.420	3.680	91,700
TETCO M1 (24-inch)	3.422	0.055	1.63	2.15	3.410	3.400	3.450	13,000
TETCO M1 (30-inch)	3.460	0.112	3.35	0.87	3.460	3.400	3.480	173,452
TX Eastern (E. LA)	3.384	0.062	1.87	0.74	3.390	3.330	3.405	57,300
TX Eastern (E. TX)	3.330	0.008	0.24	3.35	3.330	3.300	3.360	10,000
TX Eastern (S. TX)	3.322	0.057	1.75	0.94	3.320	3.300	3.385	36,000
TX Eastern (W. LA)	3.357	0.066	2.01	0.30	3.358	3.350	3.365	14,200
Tennessee Zone 0	3.332	0.018	0.54	1.68	3.325	3.285	3.410	138,600
Tennessee Zone 1	3.472	0.126	3.77	3.46	3.470	3.350	3.510	389,218
Texas Gas (LA)	3.377	0.036	1.08	0.81	3.395	3.290	3.405	41,500
Texas Gas (Zone 1)	3.377	0.079	2.40	1.23	3.390	3.318	3.400	72,800
Transco Z2	3.451	0.134	4.04	3.70	3.450	3.440	3.460	8,700
Transco Z 4	3.464	0.113	3.37	2.52	3.463	3.410	3.485	204,033
Transco Z 5	3.650	0.110	3.11	-1.35	3.650	3.650	3.650	8,800
Transco Z 3	3.455	0.100	2.98	1.98	3.460	3.390	3.480	159,383
Transco Z 1	3.170	-0.170	-5.09	-3.06	-	-	-	-
Trunkline (E. LA)	3.357	0.057	1.73	-0.59	3.355	3.350	3.360	20,300
Trunkline (W. LA)	3.417	0.095	2.86	0.98	3.410	3.410	3.435	6,000
Trunkline Zone 1A	3.383	0.047	1.41	-0.47	3.405	3.340	3.410	16,200
MID-CONTINENT								
ANR-ML7	3.750	0.130	3.59	1.08	3.750	3.700	3.800	20,000
ANR-SW	3.409	0.034	1.01	5.84	3.420	3.390	3.430	12,179
Alliance	3.678	0.021	0.57	1.04	3.680	3.610	3.700	167,200
Centerpoint East	3.255	0.030	0.93	1.75	3.265	3.210	3.350	75,200
Centerpoint No/So	3.250	0.020	0.62	-1.22	-	-	-	-
Centerpoint West	3.250	0.010	0.31	0.78	3.250	3.250	3.250	11,400
Chicago	3.672	0.029	0.80	2.83	3.670	3.410	3.715	438,355
Cons Energy Citygate	3.630	0.057	1.60	1.48	3.630	3.600	3.650	122,200
Delivery So. Star	3.325	0.031	0.94	6.84	3.325	3.320	3.335	28,000
Emerson	3.683	0.065	1.80	1.18	3.683	3.668	3.720	138,338
Enogex E Zone Pool	3.460	0.100	2.98	-0.86	-	-	-	-
Enogex W Zone Pool	3.455	0.105	3.13	1.32	3.455	3.455	3.455	24,000
Michcon Detroit CG	3.752	0.067	1.82	1.93	3.750	3.735	3.880	359,200
NGPL Amarillo	3.493	0.070	2.04	3.96	3.495	3.460	3.500	47,100
NGPL Forgan, OK	3.366	0.115	3.54	4.11	3.365	3.270	3.410	211,542
NGPL Tex/Ok	3.311	-0.007	-0.21	0.09	3.320	3.270	3.400	401,587
NNG Demarc	3.587	0.040	1.13	1.36	3.590	3.540	3.600	167,900
NNG Ventura	3.608	0.110	3.14	0.03	3.625	3.530	3.670	771,059
Northern Mid-10	3.325	0.085	2.62	-1.34	3.338	3.265	3.410	17,033
ONG at Tulsa	3.340	-0.032	-0.95	0.06	3.335	3.320	3.370	34,300
PEPL	3.325	0.091	2.81	5.35	3.345	3.270	3.380	72,700
Rex East	3.619	0.099	2.81	-0.11	3.640	3.540	3.680	198,200

© 2011, SNL Financial LC. All Rights Reserved.

Energy Pricing Trends *continued*

Gas Index (Day Ahead prices for Delivery on Nov 04, 11) *continued*

Trading Hub	Volume Wgtd. Average ($/mmBtu)	Change From Nov 03, 11 ($/mmBtu)	Volume Wgtd. Average %△ 1 Day	Volume Wgtd. Average %△ 1 Year	Trade ($/mmBtu) Median	Low	High	Trading Volume (mmBtu)
NORTHEAST								
Algon Gates	4.663	0.463	11.02	8.69	4.850	4.280	4.900	30,100
Algonquin PA-NJ	4.705	0.509	12.13	9.47	4.700	4.670	4.750	11,801
Dawn, Ont.	4.099	0.029	0.71	-2.24	4.095	4.080	4.235	413,800
Dominion N	3.510	0.040	1.15	-3.84	3.510	3.510	3.510	8,000
Dominion S	3.501	0.094	2.76	-3.10	3.510	3.420	3.700	291,963
Iroquois Waddington	4.541	0.248	5.78	1.57	4.548	4.400	4.598	90,143
Iroquois Z 2	4.515	0.236	5.52	0.78	4.510	4.480	4.570	24,000
Lebanon	3.551	0.066	1.89	-1.61	3.545	3.520	3.610	81,500
Leidy	3.684	0.154	4.36	-1.34	3.720	3.650	3.735	25,537
Natl Fuel Gas NY-PA	4.120	0.310	8.14	12.26	-	-	-	-
Niagara	4.227	0.094	2.27	1.49	4.227	4.225	4.230	22,000
TCO pool	3.502	0.065	1.89	-2.18	3.500	3.225	3.630	129,395
Tennessee Zone 5	4.671	0.407	9.55	25.56	4.665	4.500	4.800	44,948
Tennessee Zone 6	4.693	0.443	10.42	10.37	4.660	4.450	5.050	81,500
Tennessee at Dracut	4.540	0.340	8.10	15.23	-	-	-	-
Tetco M-3	3.647	0.061	1.70	-3.67	3.710	3.540	3.770	482,582
Transco Z 6 NY	3.748	0.139	3.85	-1.73	3.750	3.600	3.860	157,435
Transco Z 6 non-NY	3.702	0.111	3.09	-2.99	3.700	3.530	3.745	46,700
WEST								
AECO Storage Hub	3.254	0.110	3.50	2.46	3.255	3.238	3.300	868,735
CIG, Rocky Mountains	3.440	0.104	3.12	11.22	3.440	3.430	3.450	10,000
Cheyenne Hub	3.436	0.044	1.30	8.73	3.438	3.380	3.500	54,000
El Paso - S Mainline	3.760	0.010	0.27	8.95	3.770	3.730	3.810	16,000
El Paso - Waha Pool	3.340	0.047	1.43	2.77	3.340	3.320	3.400	77,500
El Paso Bondad	3.363	0.079	2.41	4.83	3.360	3.360	3.370	36,000
El Paso Permian	3.367	0.078	2.37	4.18	3.370	3.350	3.390	115,100
El Paso SJ	3.390	0.140	4.31	6.34	3.370	3.280	3.490	180,900
Empress	2.858	0.087	3.14	-5.80	2.857	2.828	2.930	386,925
Houston Pipeline	3.420	0.092	2.76	3.64	3.420	3.420	3.420	5,000
Kern River Station	3.743	0.108	2.97	10.74	3.740	3.740	3.755	150,300
Kern River	3.544	0.151	4.45	13.37	3.545	3.540	3.560	10,000
Kingsgate	3.590	0.080	2.28	4.30	-	-	-	-
NW Dom.-SJ Basin	3.540	0.179	5.33	12.70	-	-	-	-
NW Opal, WY	3.558	0.133	3.88	13.82	3.560	3.550	3.580	102,200
NW Stanfield, OR	3.630	0.040	1.11	4.82	3.630	3.630	3.630	2,500
NW Sumas	3.958	0.030	0.76	15.70	3.960	3.940	3.965	37,200
NW-S of Green River	3.490	0.007	0.20	11.86	-	-	-	-
NoCal Border-Malin	3.681	0.087	2.42	4.13	3.680	3.665	3.683	92,500
PG&E Gate	4.029	0.075	1.90	1.28	4.030	4.020	4.035	270,000
PG&E South	3.749	0.169	4.72	12.72	3.750	3.650	3.750	137,900
Questar	3.500	0.160	4.79	16.67	-	-	-	-
Rex West	3.480	0.087	2.56	0.29	-	-	-	-
SoCal Border	3.724	0.169	4.75	10.70	3.728	3.690	3.750	355,500
SoCal Citygate	3.853	0.172	4.67	12.96	3.870	3.840	3.875	33,000
TransW E of Thoreau	3.442	0.168	5.13	9.27	3.460	3.350	3.490	55,900
Waha Hub	3.326	0.030	0.91	1.65	3.330	3.250	3.400	366,500
West Coast Sta. 2	3.311	0.260	8.52	16.38	3.315	3.280	3.330	24,800

Additional delivery points and other energy pricing information are available at http://www.snl.com/interactivex/marketdata.aspx.

© 2011, SNL Financial LC. All Rights Reserved.

SNL Gas Spark Spread

Day ahead Prices for Delivery Nov 03, 11

Gas Location	Power Location	Gas Avg. ($/mmBtu)	Power Avg. ($/MWH)	Spark Spreads at Various Heat Rates ($) 7,000	8,000	10,000	12,000	14,000	Implied Heat Rate
TCO pool	Cinergy	3.44	36.75	12.69	9.25	2.38	-4.49	-11.37	10,692.46
Henry Hub	Entergy	3.40	33.50	9.69	6.29	-0.51	-7.31	-14.11	9,850.04
NW Sumas	Mid-C	3.93	36.25	8.75	4.83	-3.03	-10.89	-18.74	9,228.62
NNG Demarc	Minnesota	3.55	28.00	3.17	-0.38	-7.47	-14.56	-21.66	7,893.99
Chicago	N. Illinois (CE)	3.64	34.50	9.00	5.36	-1.93	-9.22	-16.50	9,470.22
Algon Gates	Nepool-Mass	4.20	42.25	12.85	8.65	0.25	-8.15	-16.55	10,059.52
PG&E Gate	NP-15	3.95	41.00	13.32	9.37	1.46	-6.45	-14.36	10,369.25
Niagara	NY Zone A	4.13	36.00	7.07	2.94	-5.33	-13.60	-21.86	8,710.38
Iroquois Z 2	NY Zone G	4.28	41.00	11.05	6.77	-1.79	-10.35	-18.91	9,581.68
Transco Z 6 NY	NY Zone J	3.61	44.50	19.24	15.63	8.41	1.19	-6.03	12,330.29
Dawn, Ont.	Ontario	4.07	31.00	2.51	-1.56	-9.70	-17.84	-25.98	7,616.71
El Paso SJ	Palo Verde	3.25	37.75	15.00	11.75	5.25	-1.25	-7.75	11,615.38
Tetco M-3	PJM West	3.59	44.79	19.69	16.10	8.93	1.76	-5.41	12,490.24
SoCal Border	SP-15	3.56	39.00	14.12	10.56	3.45	-3.66	-10.77	10,970.46

Forward Power Deals ($/MWh)

For the period Nov 03, 11

Electricity delivery point	Term	Volume wgtd. average ($/MWh)	Low trade ($/MWh)	High trade ($/MWh)	Trading volume reported (MW)
		PEAK			
		Northeast			
Nepool-Mass	Nov 14, 11-Nov 18, 11	47.00	47.00	47.00	100
NY Zone G	Nov 07, 11-Nov 11, 11	44.00	44.00	44.00	50
NY Zone G	Mar 01, 12-Apr 30, 12	50.25	50.25	50.25	50
NY Zone G	May 01, 12-May 31, 12	50.25	50.25	50.25	150
NY Zone G	Jun 01, 12-Jun 30, 12	56.00	56.00	56.00	200
PJM West	Nov 14, 11-Nov 18, 11	43.10	43.00	43.50	250
PJM West	Nov 21, 11-Nov 25, 11	42.00	42.00	42.00	200
PJM West	Dec 01, 11-Dec 31, 11	52.10	52.10	52.10	100
PJM West	Jan 01, 12-Feb 29, 12	54.50	54.40	54.70	200
PJM West	Mar 01, 12-Apr 30, 12	47.65	47.65	47.65	50
PJM West	Jul 01, 12-Aug 31, 12	60.20	60.15	60.25	100
		Midwest			
Cinergy	Nov 07, 11-Nov 07, 11	35.00	35.00	35.00	100
		OFF-PEAK			
		Northeast			
PJM West	Jan 01, 12-Feb 29, 12	38.55	38.55	38.55	50
		Midwest			
Cinergy	Nov 05, 11-Nov 06, 11	24.50	24.50	24.50	200

Nuclear Outage Report

For the period Nov 03, 11

Unit	Operator	State	Current power level (%)	Previous power level (%)	Nameplate capacity (MW)
Vermont Yankee BWR 1	Entergy Nuclear Operations Inc	VT	22	0	563.4
Wolf Creek PWR 1	Wolf Creek Nuclear Oper Corp	KS	94	95	1,235.7

© 2011, SNL Financial LC. All Rights Reserved.

Dominion Energy Index

Day	Date	Forecast or Actual Index	Above/Below Normal △	Above/Below Normal △%
UNITED STATES				
Wednesday	Nov 02, 11	18.0	1.9	12.0
Thursday	Nov 03, 11	16.0	-0.3	-1.6
Friday	Nov 04, 11	15.5	-1.2	-7.3
Saturday	Nov 05, 11	17.1	-0.1	-0.3
Sunday	Nov 06, 11	17.1	-0.5	-2.8
Monday	Nov 07, 11	14.4	-3.6	-20.0
Tuesday	Nov 08, 11	14.5	-4.0	-21.7
Wednesday	Nov 09, 11	15.1	-3.5	-18.8
GREAT LAKES				
Wednesday	Nov 02, 11	8.3	-11.7	-58.5
Thursday	Nov 03, 11	15.0	-5.6	-27.4
Friday	Nov 04, 11	20.7	-1.0	-4.5
Saturday	Nov 05, 11	24.0	1.0	4.5
Sunday	Nov 06, 11	19.2	-4.9	-20.2
Monday	Nov 07, 11	14.4	-10.5	-42.2
Tuesday	Nov 08, 11	16.3	-9.7	-37.2
Wednesday	Nov 09, 11	20.5	-6.3	-23.5
GREAT PLAINS				
Wednesday	Nov 02, 11	17.0	-2.0	-10.7
Thursday	Nov 03, 11	18.2	-1.7	-8.4
Friday	Nov 04, 11	22.7	0.6	2.9
Saturday	Nov 05, 11	15.7	-7.7	-33.1
Sunday	Nov 06, 11	11.0	-13.5	-55.1
Monday	Nov 07, 11	14.0	-11.7	-45.7
Tuesday	Nov 08, 11	19.2	-7.2	-27.3
Wednesday	Nov 09, 11	23.4	-3.8	-14.0
LOWER MISSISSIPPI				
Wednesday	Nov 02, 11	13.7	2.1	17.8
Thursday	Nov 03, 11	10.2	-1.3	-11.2
Friday	Nov 04, 11	7.5	-3.8	-33.5
Saturday	Nov 05, 11	8.6	-2.5	-22.5
Sunday	Nov 06, 11	11.7	0.5	4.6
Monday	Nov 07, 11	14.1	3.1	28.2
Tuesday	Nov 08, 11	19.0	8.1	74.2
Wednesday	Nov 09, 11	14.0	2.8	25.5
MID-ATLANTIC				
Wednesday	Nov 02, 11	15.7	5.2	49.9
Thursday	Nov 03, 11	11.5	0.3	2.5
Friday	Nov 04, 11	15.1	2.6	20.8
Saturday	Nov 05, 11	22.8	9.3	68.2
Sunday	Nov 06, 11	21.4	6.4	43.0
Monday	Nov 07, 11	12.1	-4.2	-25.9
Tuesday	Nov 08, 11	4.5	-12.6	-73.7
Wednesday	Nov 09, 11	4.5	-13.2	-74.7
NEW ENGLAND				
Wednesday	Nov 02, 11	23.9	6.0	33.4
Thursday	Nov 03, 11	18.9	0.6	3.2
Friday	Nov 04, 11	21.5	2.8	15.0
Saturday	Nov 05, 11	26.7	7.7	40.3
Sunday	Nov 06, 11	24.9	5.3	27.1
Monday	Nov 07, 11	17.9	-2.4	-12.0
Tuesday	Nov 08, 11	11.8	-9.0	-43.3
Wednesday	Nov 09, 11	11.4	-10.1	-47.0
PACIFIC				
Wednesday	Nov 02, 11	23.1	9.5	70.6
Thursday	Nov 03, 11	15.2	2.2	17.0
Friday	Nov 04, 11	12.9	0.3	2.5
Saturday	Nov 05, 11	16.4	4.2	34.3
Sunday	Nov 06, 11	15.1	3.0	25.2
Monday	Nov 07, 11	14.7	2.8	23.4
Tuesday	Nov 08, 11	12.6	0.8	6.6
Wednesday	Nov 09, 11	11.7	1.0	9.0
ROCKY MOUNTAINS				
Wednesday	Nov 02, 11	47.7	23.5	97.6
Thursday	Nov 03, 11	42.5	18.0	73.4
Friday	Nov 04, 11	31.4	6.2	24.7
Saturday	Nov 05, 11	35.7	9.9	38.5
Sunday	Nov 06, 11	37.6	11.3	43.1
Monday	Nov 07, 11	40.2	13.2	48.9
Tuesday	Nov 08, 11	40.5	12.3	43.9
Wednesday	Nov 09, 11	36.0	6.9	23.8
SOUTH ATLANTIC				
Wednesday	Nov 02, 11	16.6	1.2	8.0
Thursday	Nov 03, 11	18.0	2.9	19.1
Friday	Nov 04, 11	14.8	-0.1	-0.4
Saturday	Nov 05, 11	17.8	3.0	20.6
Sunday	Nov 06, 11	20.1	5.5	37.9
Monday	Nov 07, 11	14.9	0.1	0.7
Tuesday	Nov 08, 11	17.6	2.7	18.3
Wednesday	Nov 09, 11	19.6	4.5	29.8
SOUTHWEST				
Wednesday	Nov 02, 11	25.6	5.1	24.8
Thursday	Nov 03, 11	18.4	-1.9	-9.2
Friday	Nov 04, 11	10.9	-9.0	-45.3
Saturday	Nov 05, 11	5.0	-14.6	-74.5
Sunday	Nov 06, 11	10.4	-8.9	-46.2
Monday	Nov 07, 11	12.6	-6.3	-33.3
Tuesday	Nov 08, 11	14.3	-4.3	-23.3
Wednesday	Nov 09, 11	14.8	-3.2	-17.6

The Dominion Energy Index, maintained by The Dominion Energy Services Corp., measures actual and forecast demand for heating and cooling energy. It is designed to be more precise than the current heating degree days and cooling degree days indexes. The first reading in each regional list is the actual energy demand measured the day the forecast is made. The forecast energy demand for the following week for a given region follows the actual reading in the table. "Normals" for each region for each day have been calculated using 30-year weather averages.

© 2011, SNL Financial LC. All Rights Reserved.

NYMEX Natural Gas Futures

For the period Nov 03, 11

Contract	Prior Settle ($/mmBtu)	High ($/mmBtu)	Low ($/mmBtu)	Settle ($/mmBtu)	Change ($/mmBtu)
Dec-2011	3.749	3.804	3.730	3.778	0.029
Jan-2012	3.882	3.941	3.872	3.901	0.019
Feb-2012	3.893	3.950	3.883	3.909	0.016
Mar-2012	3.867	3.920	3.857	3.882	0.015
Apr-2012	3.862	3.919	3.851	3.879	0.017
May-2012	3.897	3.953	3.886	3.913	0.016
Jun-2012	3.939	3.995	3.928	3.953	0.014
Jul-2012	3.986	4.043	3.975	3.999	0.013
Aug-2012	4.011	4.068	4.005	4.024	0.013
Sep-2012	4.013	4.069	4.008	4.026	0.013
Oct-2012	4.053	4.107	4.047	4.065	0.012
Nov-2012	4.193	4.243	4.187	4.203	0.010
Dec-2012	4.452	4.500	4.443	4.464	0.012
Jan-2013	4.584	4.635	4.575	4.592	0.008
Feb-2013	4.571	4.610	4.568	4.579	0.008
Mar-2013	4.518	4.554	4.519	4.527	0.009
Apr-2013	4.423	4.460	4.420	4.432	0.009
May-2013	4.439	4.450	4.450	4.447	0.008

Changes in settlement price with zero volume mean the settlement price is implied. No actual trading took place for these contracts on the given day. Price is based on delivery at the Henry Hub in Louisiana, which serves markets throughout the U.S. East Coast, the Gulf Coast, the Midwest, and up to the Canadian border.

SNL Daily OTC Coal and Emissions Assessments

Nov 03, 11 Product	Price ($/ton)	Change (%) 1 day	Change (%) 1 week
NYMEX Big Sandy			
December 2011	72.90	0.28	NA
Q1 2012	72.98	0.27	-1.38
CSX/Rail			
December 2011	77.25	0.48	NA
Q1 2012	75.60	0.23	-1.28
PRB 8,800			
December 2011	14.10	-0.70	NA
Q1 2012	13.95	-0.57	-2.79
PRB 8,400			
December 2011	11.15	-1.76	NA
Q1 2012	11.00	-1.35	-3.93

Nov 03, 11 Product	Price ($/credit)	Change (%) 1 day	Change (%) 1 week
SO2			
2010	1.13	0.00	0.00
2011	1.00	0.00	0.00
2012	0.56	0.00	0.00
2013	0.56	0.00	0.00
2014	0.56	0.00	0.00
2015	0.56	0.00	0.00
NOx			
2011	5.75	0.00	-37.84
2012	5.75	0.00	-37.84

Data provided by Evolution Markets and Amerex Brokers

© 2011, SNL Financial LC. All Rights Reserved.

SNL RECs Index

Week ending 10/28/11

Product	Term	Price	Product	Term	Price	Product	Term	Price
CA RPS-REC	2011	3.58	MA Class I	2012	30.46	NJ Solar REC	2011	641.67
CA RPS-REC	11-13	3.88	MA Class I	2013	30.96	NJ Solar REC	2012	227.50
CA RPS-REC	11-16	NA	MA Class II WTE	2011	3.13	NJ Solar REC	2013	228.75
CT Class I REC	2011	28.50	MA Solar	2011	528.75	OH Contiguous REC	2010	NA
CT Class I REC	2012	28.50	MD Solar	2010	NA	OH In-State Solar	2011	370.00
CT Class I REC	2013	28.38	MD Solar	2011	211.25	OH Located REC	2011	13.88
CT Class II REC	2011	0.48	MD Tier I	2010	0.70	PA Solar REC	2011	30.00
CT Class II REC	2012	0.80	MD Tier I	2011	1.03	PA Solar REC	2012	41.25
CT Class III REC	2011	11.38	MD Tier II	2010	0.18	PA Tier 1 REC	2011	1.39
CT Class III REC	2012	10.88	ME Class I	2011	14.63	PA Tier 1 REC	2012	1.48
CT Class III REC	2013	11.50	ME Class I	2012	16.25	PA Tier 2 REC	2010	0.14
DC Solar REC	2011	255.00	NH Class I	2011	30.00	PA Tier 2 REC	2011	0.19
DC Tier I REC	2011	1.18	NH Class II	2011	42.50	PA Tier 2 REC	2012	0.50
DE EXISTING REC	2010	0.88	NH Class III	2011	NA	RI Existing REC	2011	0.88
DE NEW REC	2010	1.30	NH Class IV	2011	NA	RI NEW REC	2011	29.00
DE NEW REC	2011	1.15	NJ Class I REC	2011	1.23	TX REC	2010	1.53
DE Solar REC	2010	82.50	NJ Class I REC	2012	1.30	TX REC	2011	1.60
MA APS	2011	NA	NJ Class I REC	2013	1.59	TX REC	2012	1.68
MA APS	2012	19.63	NJ Class II REC	2011	0.44	WA RPS	11-14	3.50
MA Class I	2011	30.50	NJ Class II REC	2012	0.69	WA RPS	15-18	5.50

Data is compiled from a range of market indicatives and do not necessarily represent completed trades. CA and WA RPS figures do not contain data from Evolution Markets.
Data for SNL RECs index provided by:
Evolution Markets: http://new.evomarkets.com/
Tradition Financial Services: http://www.tfsbrokers.com/
Clear Energy Brokerage and Consulting: http://www.clearenergybrokerage.com/
Karbone: http://www.karbone.com/
Please contact data providers for more detailed or specific transaction data or REC markets not covered by SNL index.
Source: SNL Energy

©2011, SNL Financial LC. All Rights Reserved. Confidential Subject Matter. WARNING! *SNL Power Daily with Market Report* contains copyrighted subject matter and confidential information owned solely by SNL Financial LC ("SNL"). Reproduction, distribution or use of this newsletter in violation of this license constitutes copyright infringement in violation of federal and state law. SNL hereby provides consent to use the "email this story" feature to redistribute articles within the subscriber's company. Although the information in this report has been obtained from sources that SNL believes to be reliable, SNL does not guarantee its accuracy.

© 2011, SNL Financial LC. All Rights Reserved.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

October 29, 2011

Mr. Alden Briggs
Chair, NPCC Task Force on Coordination of Planning
New Brunswick System Operator
77 Canada Street
Fredericton, New Brunswick, Canada E3B 5G4
email: alden.briggs@nbso.ca

Re: TFCO Review of the of the Proposed Modification to the Maxcys-Bucksport Special Protection System

Sir / Madam:

Sections 2.3 and 2.3.3 of Appendix B, "Procedure for Review of Special Protection Systems," of NPCC Regional Reliability Reference Directory 7, "Special Protection Systems," charge the NPCC Task Force on Coordination of Operation to review the operability of a newly proposed Type I special protection system or a modification of an existing Special Protection System:

> **2.3 "If the proposing entity expects the Special Protection System to have inter-Area or inter-Regional consequences, or if the TFSS or TFCP review concludes this to be the case, TFCP will request the Task Force on Coordination of Operation (TFCO), the Task Force on System Protection (TFSP) and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity."**
>
> **2.3.3 "TFCO will review the operability of the Special Protection System and forward a summary of their findings to TFCP, TFSS and TFSP. This summary will include a statement as to whether the Task Force has any objections to its modification or installation."**

At its meeting of October 6 and 7, 2011, the NPCC Task Force on Coordination of Operation reviewed the proposed modification to the Maxcys-Bucksport Special Protection System.

The Maine Power Reliability Program (MPRP), which will strengthen the transmission system in northern Maine, will eliminate the need for the Maxcys-Bucksport SPS by the spring of 2014. During the ongoing construction, modifications to the Maxcys-Bucksport special protection system will be required. The energization of one portion of a new transmission path, 345 kV Section 3023 between the Albion Road and Orrington Substations, together with the Albion Road 345-115 kV autotransformer, will necessitate a modification of the Maxcys-

Bucksport SPS. These revisions will include setpoints for triggering the transfer trip and generation rejection signals associated with the SPS. The Maxcys-Bucksport SPS forces a controlled separation of Bangor Hydro and the Maritimes by opening transmission facilities for contingencies on Section 388 between the Orrington and Maxcys substations and Section 392 between the Maxcys and Maine Yankee substations. The energization of Section 3023 and the Albion Road autotransformer provides an additional transmission path south of Orrington that must also be tripped following contingencies on Sections 388 or 392 in order to maintain the controlled separation of Bangor Hydro and the Maritimes. It is currently expected that the modified SPS will be required from the autumn of 2012 until the spring of 2014, at which time the Maxcys-Bucksport special protection system is scheduled to be removed.

Following its review of the proposed revisions to the Maxcys-Bucksport special protection system, the NPCC Task Force on Coordination of Operation concluded that these proposed changes will not impact the operability of the system and recommends its approval as an NPCC Type I special protection system.

Thank you for your attention to this important issue.

Very truly yours,

Dave Daley

David A. Daley
Chair, NPCC Task Force on
Coordination of Operation

JDC:cd

cc: Members, Reliability Coordinating Committee
Members, Task Force on Coordination of Operation
Members, Task Force on Coordination of Planning
Members, Task Force on System Protection
Members, Task Force on System Studies

From:	John G. Mosier Jr.
To:	alden.briggs@nbso.ca
Cc:	tfcp; tfss; tfsp; tfco-members
Subject:	TFCO Review of the of the Proposed Modification to the Maxcys-Bucksport Special Protection System
Date:	Friday, November 04, 2011 12:40:16 PM
Attachments:	20111029_DD-AB_Maxcys-Bucksport_SPS_Modification.doc

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

October 29, 2011

Mr. Alden Briggs
Chair, NPCC Task Force on Coordination of Planning
New Brunswick System Operator
77 Canada Street
Fredericton, New Brunswick, Canada E3B 5G4
email: alden.briggs@nbso.ca

Re: TFCO Review of the of the Proposed Modification to the Maxcys-Bucksport Special Protection System

Sir / Madam:

Sections 2.3 and 2.3.3 of Appendix B, "Procedure for Review of Special Protection Systems," of NPCC Regional Reliability Reference Directory 7, "Special Protection Systems," charge the NPCC Task Force on Coordination of Operation to review the operability of a newly proposed Type I special protection system or a modification of an existing Special Protection System:

> **2.3 "If the proposing entity expects the Special Protection System to have inter-Area or inter-Regional consequences, or if the TFSS or TFCP review concludes this to be the case, TFCP will request the Task Force on Coordination of Operation (TFCO), the Task Force on System Protection (TFSP) and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity."**
>
> **2.3.3 "TFCO will review the operability of the Special Protection System and forward a summary of their findings to TFCP, TFSS and TFSP. This summary will include a statement as to whether the Task Force has any objections to its modification or installation."**

At its meeting of October 6 and 7, 2011, the NPCC Task Force on Coordination of Operation reviewed the proposed modification to the Maxcys-Bucksport Special Protection System.

The Maine Power Reliability Program (MPRP), which will strengthen the transmission system in northern Maine, will eliminate the need for the Maxcys-Bucksport

SPS by the spring of 2014. During the ongoing construction, modifications to the Maxcys-Bucksport special protection system will be required. The energization of one portion of a new transmission path, 345 kV Section 3023 between the Albion Road and Orrington Substations, together with the Albion Road 345-115 kV autotransformer, will necessitate a modification of the Maxcys-Bucksport SPS. These revisions will include setpoints for triggering the transfer trip and generation rejection signals associated with the SPS. The Maxcys-Bucksport SPS forces a controlled separation of Bangor Hydro and the Maritimes by opening transmission facilities for contingencies on Section 388 between the Orrington and Maxcys substations and Section 392 between the Maxcys and Maine Yankee substations. The energization of Section 3023 and the Albion Road autotransformer provides an additional transmission path south of Orrington that must also be tripped following contingencies on Sections 388 or 392 in order to maintain the controlled separation of Bangor Hydro and the Maritimes. It is currently expected that the modified SPS will be required from the autumn of 2012 until the spring of 2014, at which time the Maxcys-Bucksport special protection system is scheduled to be removed.

Following its review of the proposed revisions to the Maxcys-Bucksport special protection system, the NPCC Task Force on Coordination of Operation concluded that these proposed changes will not impact the operability of the system and recommends its approval as an NPCC Type I special protection system.

Thank you for your attention to this important issue.

Very truly yours,

Dave Daley

David A. Daley
Chair, NPCC Task Force on
Coordination of Operation

JDC:cd

cc: Members, Reliability Coordinating Committee
Members, Task Force on Coordination of Operation
Members, Task Force on Coordination of Planning
Members, Task Force on System Protection
Members, Task Force on System Studies

From: Lee R. Pedowicz
To: rscmembers; donald.e.nelson@state.ma.us; rjfalsetti@cogeco.ca
Subject: FW: NERC Industry Webinar: Project 2007-12 Frequency Response - November 14, 2011
Date: Friday, November 04, 2011 12:49:25 PM

Good afternoon.

For information.

Have a nice weekend!!

Lee

From: Wendy Sandberg [mailto:Wendy.Sandberg@nerc.net]
Sent: Friday, November 04, 2011 11:59 AM
To: Wendy Sandberg
Subject: NERC Industry Webinar: Project 2007-12 Frequency Response - November 14, 2011

Industry Webinar

Project 2007-12 Frequency Response and Frequency Bias Setting

November 14, 2011 | 1:00–5:00 p.m. ET

Click here for: Webinar Registration

Teleconference: 800.704.5185 | **Access Code:** 8816510 | **Broadcast Audio Code:** 838373

Background: Frequency Response is a critical component to the reliable operation of the bulk power system, particularly during disturbances and restoration. There is evidence of continuing decline in Frequency Response over the past 10 years, but no confirmed reason for the apparent decline. In FERC Order 693 the Commission directed the ERO to:

1. Determine the appropriate periodicity of Frequency Response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and

2. Define the necessary amount of Frequency Response needed for reliable operation for each Balancing Authority with methods of obtaining and measuring that the Frequency Response is achieved. The proposed standard sets a minimum Frequency

Response obligation for each Balancing Authority, provides a uniform calculation of Frequency Response and Frequency Bias Settings that transition to values closer to natural Frequency Response, and encourages coordinated AGC operation.

For more information or assistance, please contact Darrel Richardson (via email) or at (609) 613-1848 or Wendy Sandberg (via email) or at (404) 446-9735.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Wendy Sandberg
Standards Development Administrative Assistant
North American Electric Reliability Corporation
wendy.sandberg@nerc.net
(404) 446-9735 (O)
(404) 823-1366 (C)

NERC Reliability | Accountability

This email and any of its attachments may contain NERC proprietary information that is privileged, confidential, or subject to copyright belonging to NERC. This message and any attachments may contain confidential information protected by the attorney-client or other privilege. This email is intended solely for the use of the individual or entity to which it is addressed. If you are not the intended recipient of this email, you are hereby notified that any dissemination, distribution, copying, or action taken in relation to the contents of and attachments to this email is strictly prohibited and may be unlawful. If you receive this email in error, please notify the sender immediately and permanently delete the original and any copy of this email and any printout

---
You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1275338-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Standards 101

RELIABILITY | ACCOUNTABILITY






Presentation Agenda

- NERC Overview
- Standards Process



NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Overview

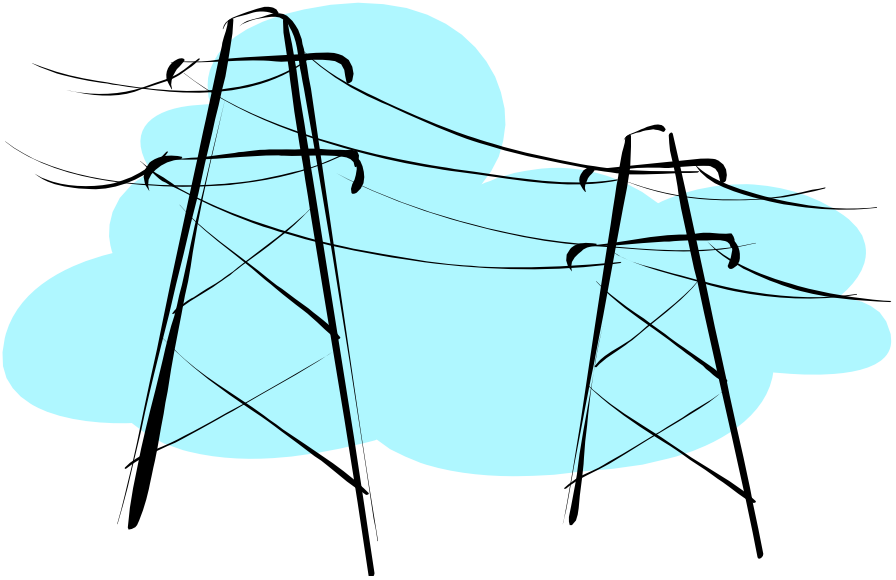
RELIABILITY | ACCOUNTABILITY






What is NERC's role in the industry?

- Mission: Ensure the reliability of the North American bulk power system by…
  - Holding entities accountable for compliance with mandatory reliability standards
  - Acting as a catalyst for positive change within the industry

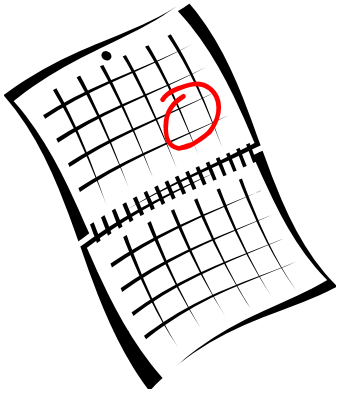


Defining Reliability

- NERC defines a **reliable** bulk power system as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures reduce the amount of available electricity.
- This means:
  1. Adequacy – sufficient resources
  2. Security – ability of system to withstand sudden and unexpected disturbances

Reliability History: Key Dates

November 9, 1965 – Northeast Blackout



1968: National Electric Reliability Council (NERC) established by the electric industry

2002: NERC operating policy and planning standards became mandatory and enforceable in Ontario, Canada

August 14, 2003 Blackout

2005: U.S. Energy Policy Act of 2005 creates the Electric Reliability Organization (ERO)

2006: Federal Energy Regulatory Commission (FERC) certified NERC as the ERO; Memorandum of Understanding (MOUs) with some Canadian Provinces

2007: North American Electric Reliability Council (NERC) became the North American Electric Reliability Corporation (NERC); FERC issued Order 693 approving 83 of 107 proposed Reliability Standards; became mandatory and enforceable

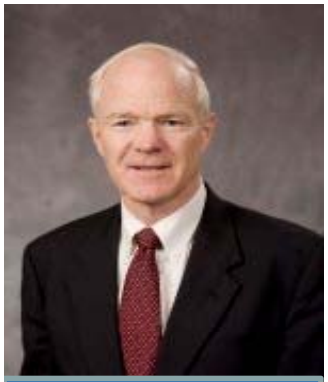
What does it mean to be the ERO?

- Only one ERO, overseen by U.S. and Canadian regulatory authorities (FERC and the provinces)
  - Responsible for developing/enforcing reliability standards
  - Independent of owners, operators, users
  - Adhere to rules governing standards development, compliance enforcement, budgeting

What does NERC do?

- Develops and enforces reliability standards
- Monitors the bulk power system
- Assesses adequacy
- Audits owners, operators, and users for preparedness
- Educates and trains industry personnel

NERC's Board of Trustees


J. Anderson


T. Berry


G. Cauley

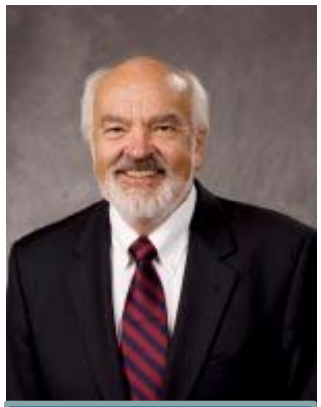

V. Bailey


P. Barber


J. Case


F. Gorbet


D. Goulding


K. Peterson


B. Scherr


J. Schori


R. Thilly

NERC Membership

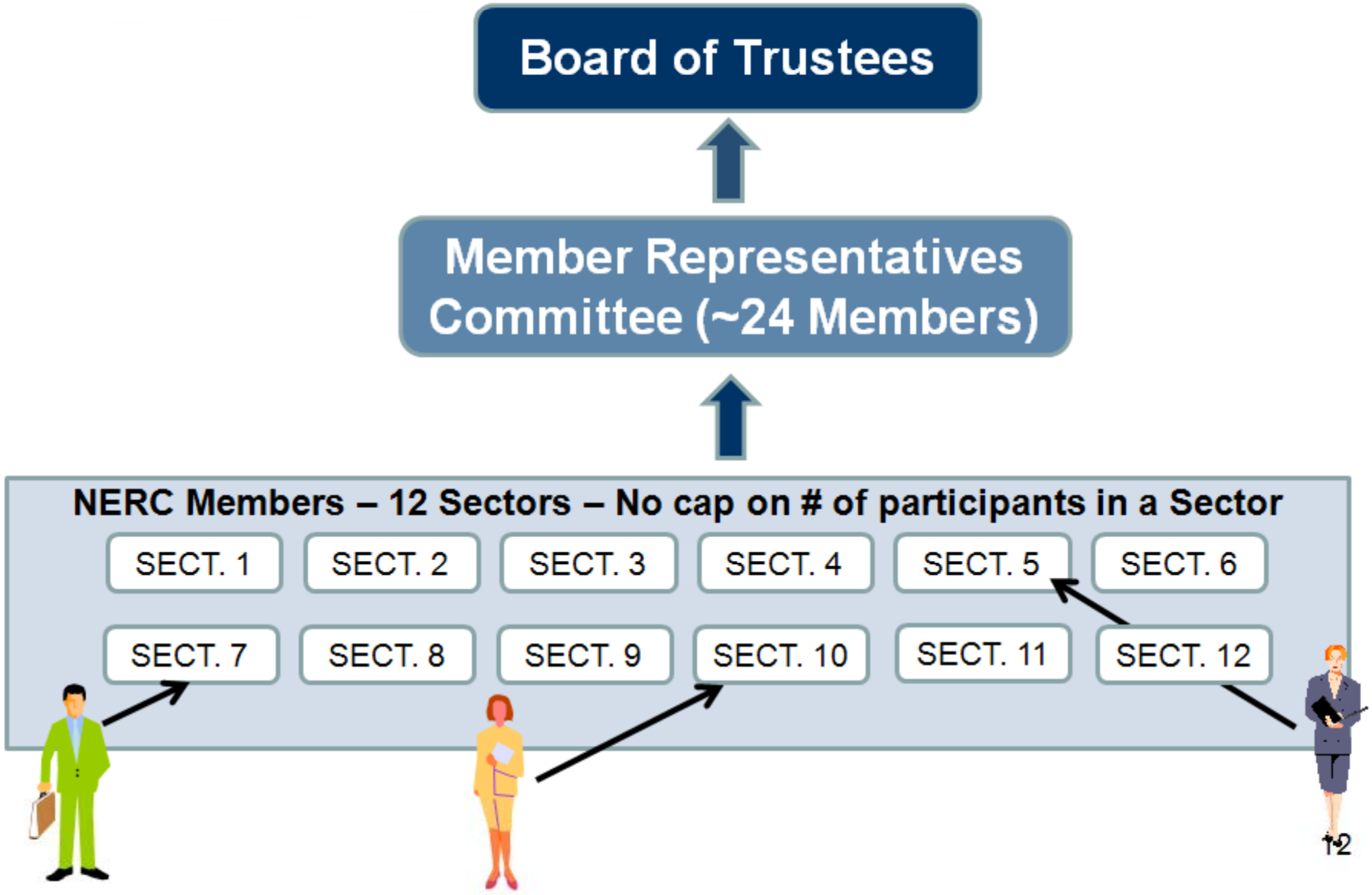
- Open to all entities interested in the bulk power system
- Twelve membership categories:
  - Investor-owned utility
  - State or municipal utility
  - Cooperative utility
  - Federal or provincial utility/power marketing administrator
  - Transmission dependent utility



NERC Membership, cont.

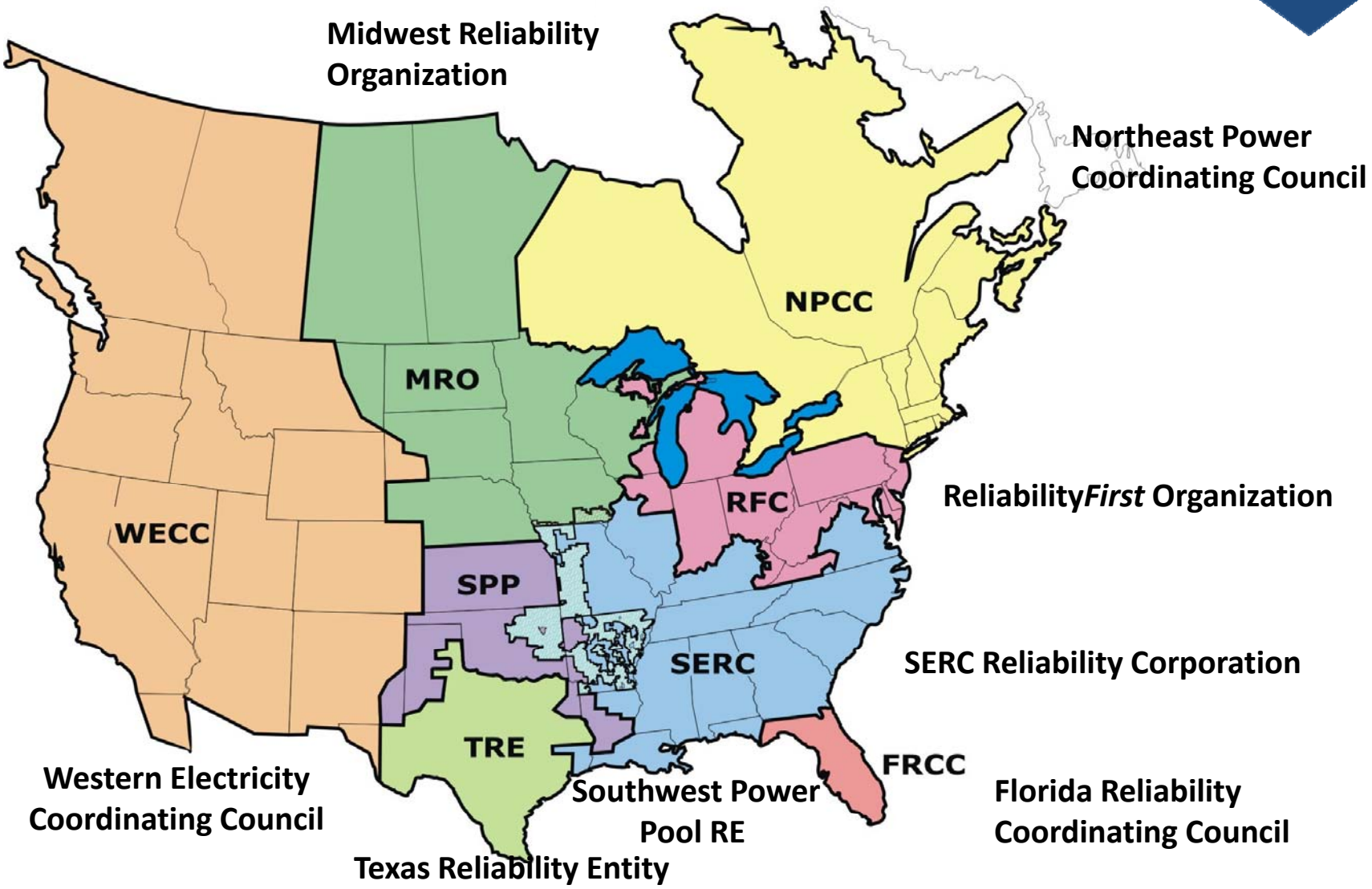
- More membership categories:
  - Merchant electricity generator
  - Electricity marketer
  - Large end-use electricity customer
  - Small end-use electricity customer
  - Independent system operator/regional transmission organization
  - Regional Entity
  - Government Representative

Hierarchy Showing Relationship of NERC Members to Board of Trustees



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Regions



Eight NERC Regions

- Perform delegated functions:
  - Compliance
  - Regional standards
  - Organization registration
  - Reliability assessments
- Regional consistency key for transparency, predictability, and uniform outcomes

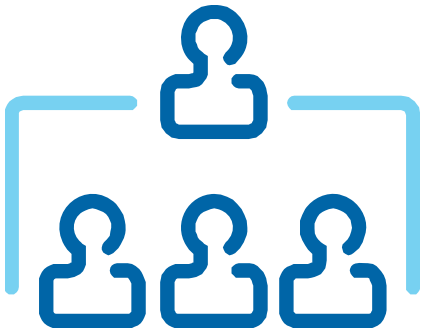
NERC Funding

- NERC and Regional Entities allocate operating costs to load-serving entities (LSEs):
  - LSEs are owners, operators, and users of the bulk power system responsible for delivering electricity to retail customers



NERC Departments

- Compliance Enforcement
- Compliance Operations
- Critical Infrastructure Protection (CIP)
- Investigations
- Operations, Planning, and Delivery
- Reliability Assessment and Performance Analysis (RAPA)
- Reliability Initiatives and System Analysis
- Situational Awareness
- Standards
- Governmental Relations
- Legal and Regulatory
- Training



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC's Standards Process

RELIABILITY | ACCOUNTABILITY





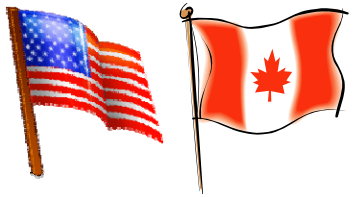

NERC's Standards Process

- In 2010, a new process was developed with input from Standards Committee, Results-Based Process Ad Hoc Team, stakeholders, and regulators
- FERC approved the Standard Processes Manual on September 3, 2010
- Goals:
  - Improve efficiency
  - Improve quality
  - Preserve American National Standards Institute (ANSI) accreditation

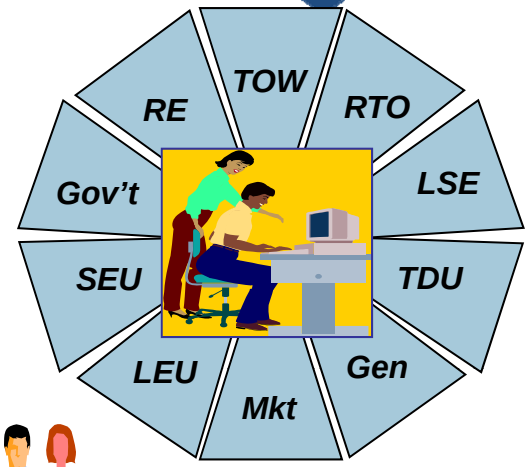
Roles and Responsibilities



Board of Trustees



Regulators



Ballot Body



Standards Committee



Drafting Teams



Stakeholders



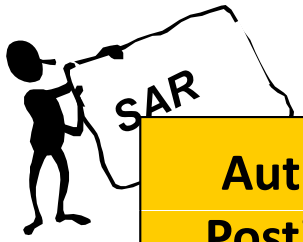
Standards Staff

Ballot Pools



Standards Committee

- Prioritizing standards development activities
- Reviews actions to ensure the standards development process is followed
- Reviews and authorizes Standard Authorization Requests (SARs)
- Manages progress of SARs and standards development efforts
- Reviews and authorizes drafting new or revised standards and their supporting documents
- Makes appointments to drafting teams



Authorize Posting SAR

Appoint DT

Draft Standard

Collect Informal Feedback

Revise

Submit Standard for QR

Revise

Post for Comment

Consider/ Respond/Revise

Submit Standard for QR

Revise

Post for Comment/ Ballot

Consider/ Respond/Revise



Implement

Regulatory Agencies Approve

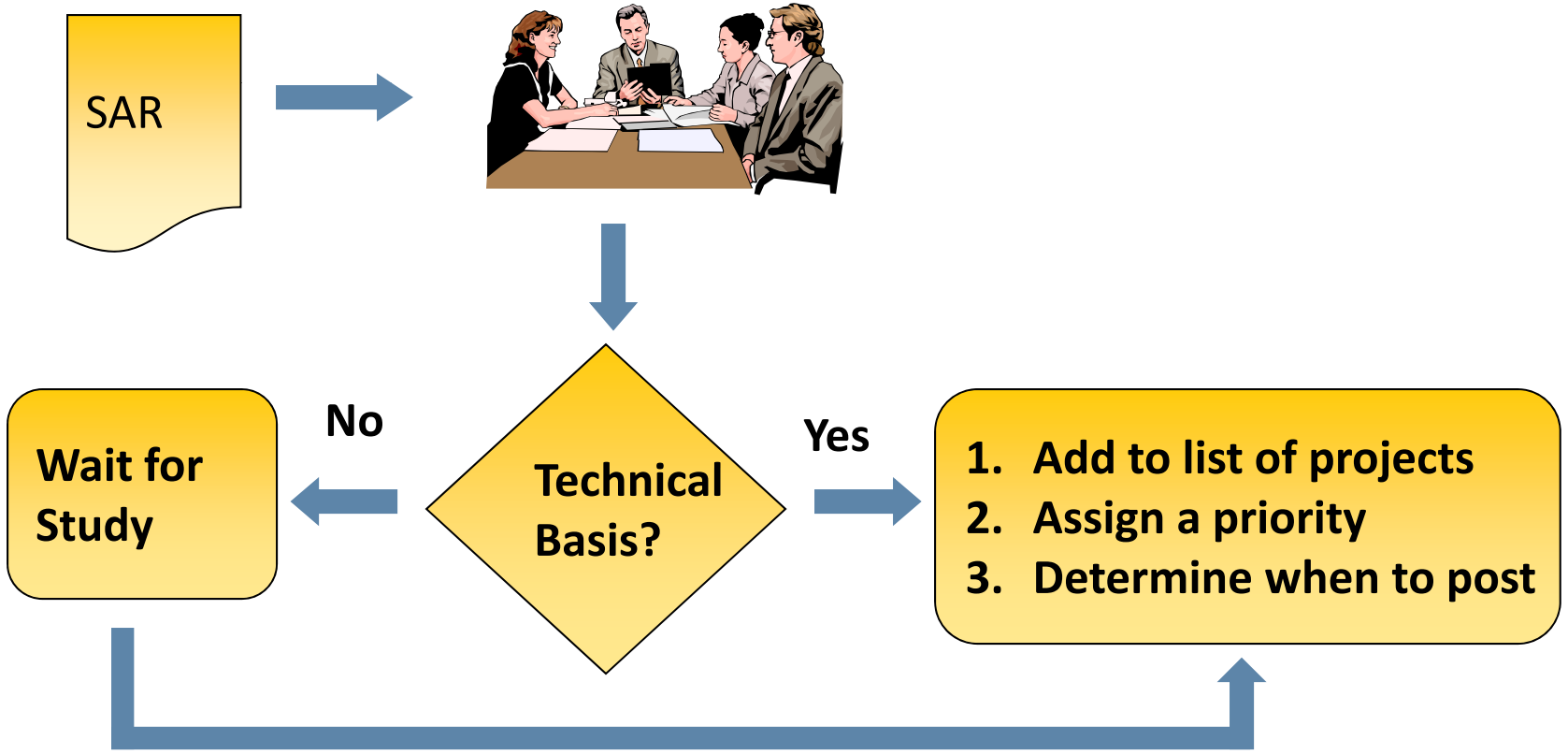
Board Adopts

Post for Recirculation Ballot

Standard Authorization Requests

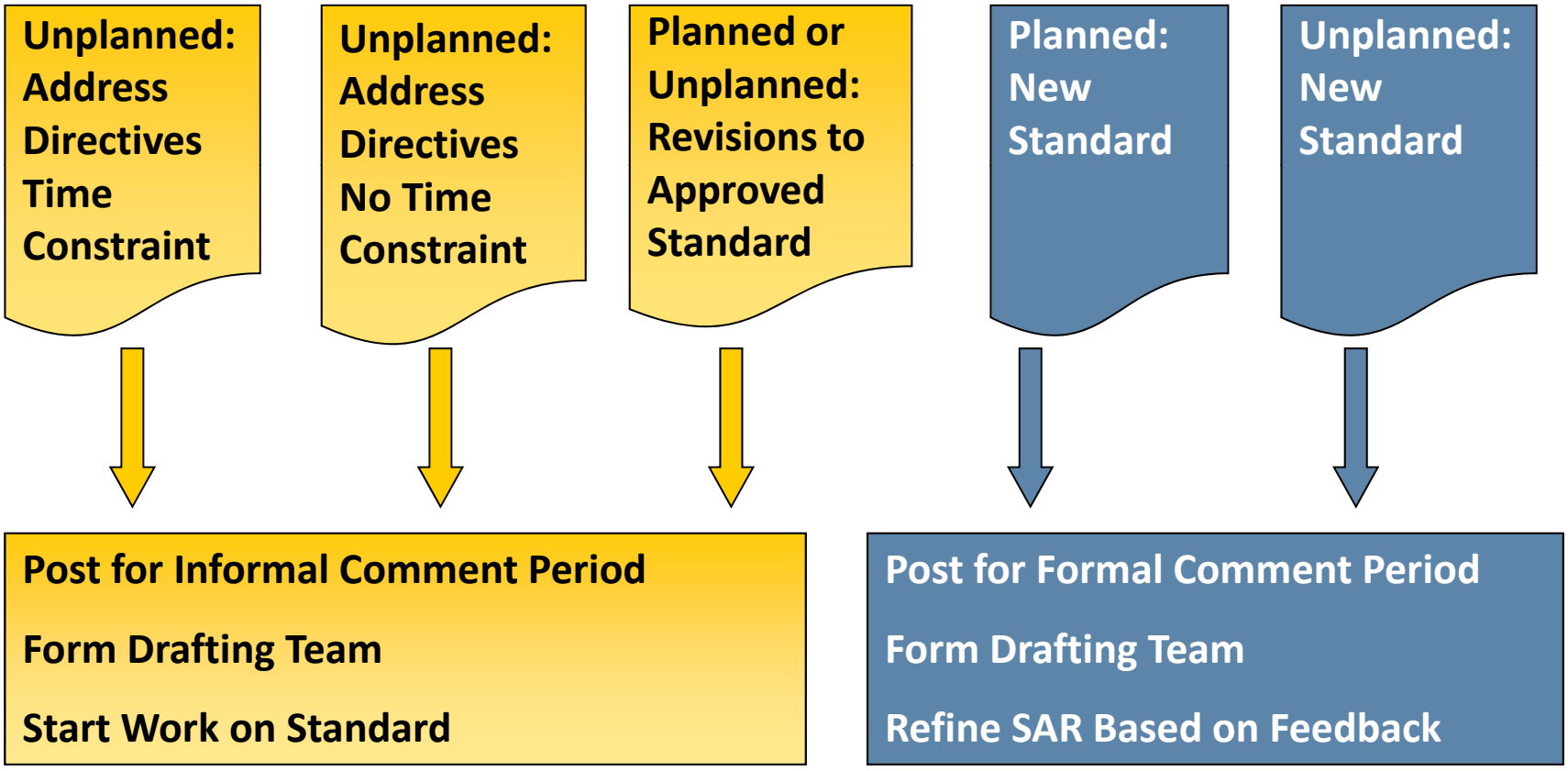
Every valid SAR is accepted.

SARs need a technical basis and are posted based on priority.



Processing of SARs

Post proposals for "new" standards for formal comment period; collect informal comments for others.



Roles and Responsibilities of Drafting Teams

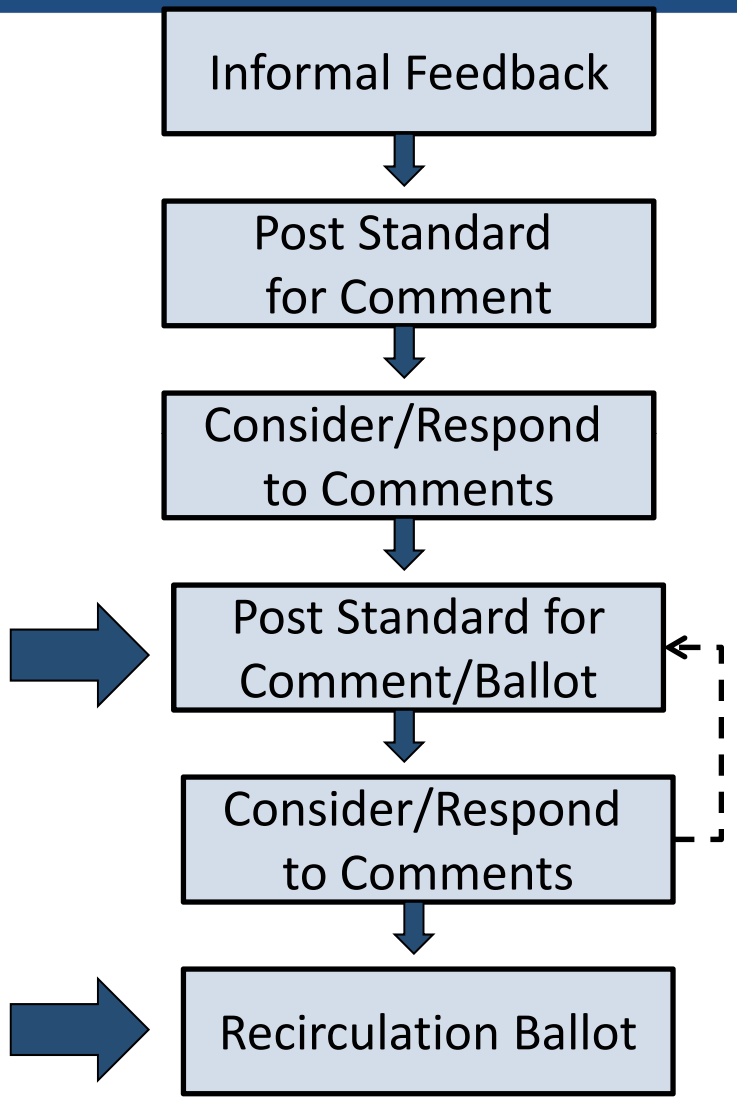
- Develop an excellent, technically correct standard that helps provide an adequate level of bulk power system reliability and achieves stakeholder consensus
  - Stay within the scope of the SAR
  - Address regulatory directives and stakeholder issues
  - Ensure standard meets criteria for approval
- Develop initial set of Violation Risk Factors (VRFs)and Violation Severity Levels (VSLs) and associated reasoning
- Produce a realistic implementation plan
- Develop supporting documents (optional)

Drafting Team Formation and Support

- If a team is formed to address the SAR, the same team develops the standard
- Includes a technical writer, if needed
- Technical experts provide content for requirements
- Technical writer drafts language for technical experts
- Technical experts have “power of veto”



Stakeholder Consensus Process



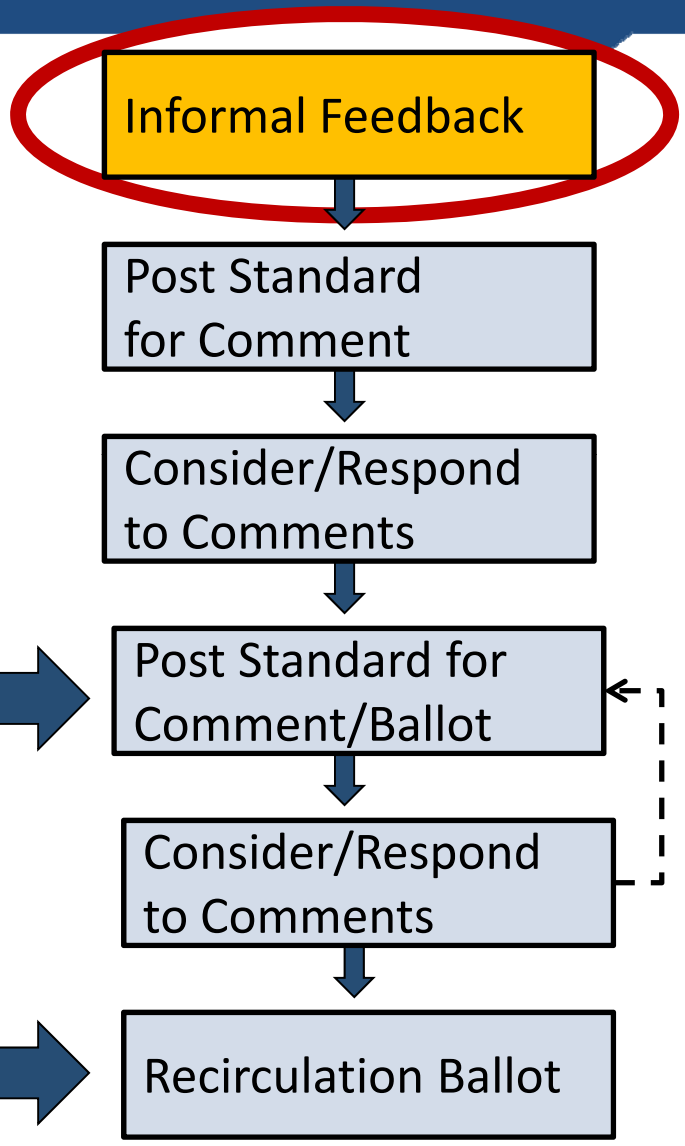
New/Successive Ballot:

At this step, the standard is either "new" or significantly changed from the last version posted for comment/ ballot. The ballot record starts with no votes and no comments.

Recirculation Ballot:

At this step, there have been no significant changes to the standard from the last ballot. The ballot record starts with all votes and comments from the previous ballot.

Stakeholder Consensus Process



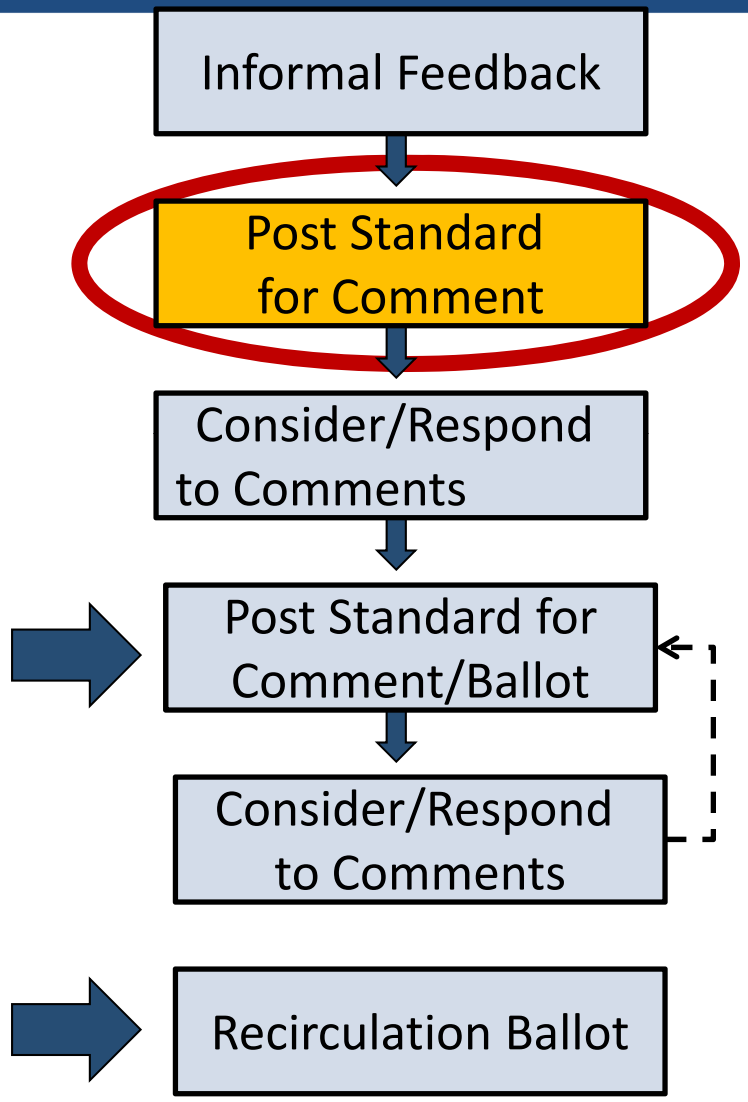
New/Successive Ballot:
At this step, the standard is either "new" or significantly changed from the last version posted for comment/ ballot. The ballot record starts with no votes and no comments.

Recirculation Ballot:
At this step, there have been no significant changes to the standard from the last ballot. The ballot record starts with all votes and comments from the previous ballot.

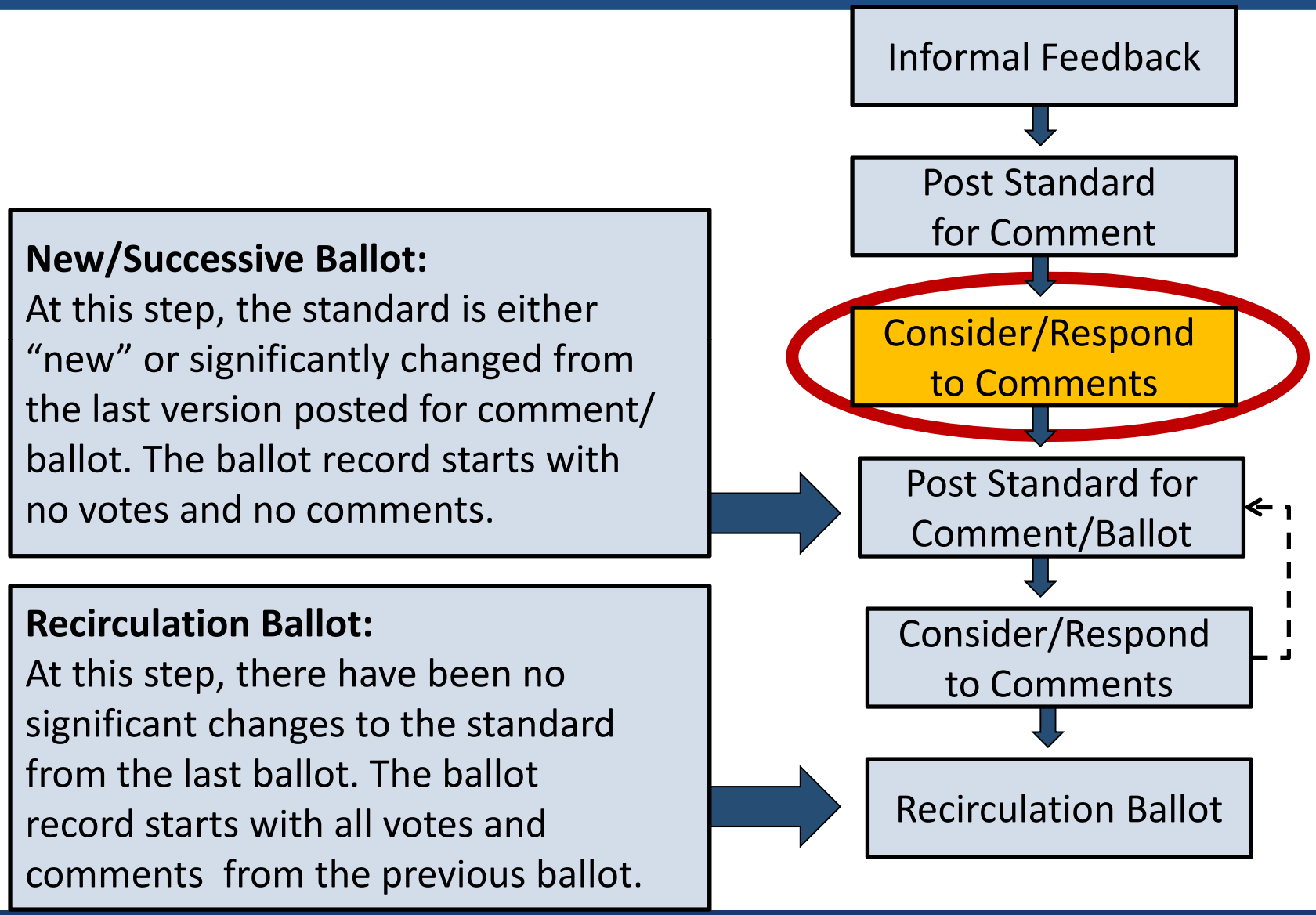
Stakeholder Consensus Process

New/Successive Ballot:
At this step, the standard is either "new" or significantly changed from the last version posted for comment/ ballot. The ballot record starts with no votes and no comments.

Recirculation Ballot:
At this step, there have been no significant changes to the standard from the last ballot. The ballot record starts with all votes and comments from the previous ballot.



Stakeholder Consensus Process



Building Consensus with Comments

- Stakeholder feedback is essential
- The best comments offer suggested replacement language first and then support that suggested language with rationale
- If a stakeholder cannot suggest alternate language, he or she should still make sure to support his or her claim with sound technical rationale

Sample Comments

- In attachments 1, 2, and 3 the six month requirement for notice is too short in many cases. We suggest nine months to one year. Six months is not enough time for budgeting and construction scheduling.
- The Generator Owner appears to be the logical choice. GO has the access to the equipment records, GOP may not.

Sample Comments

- Disagree with R2 as written.
- Disagree with assigning requirement to the GO.
- Definition is a little loose.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

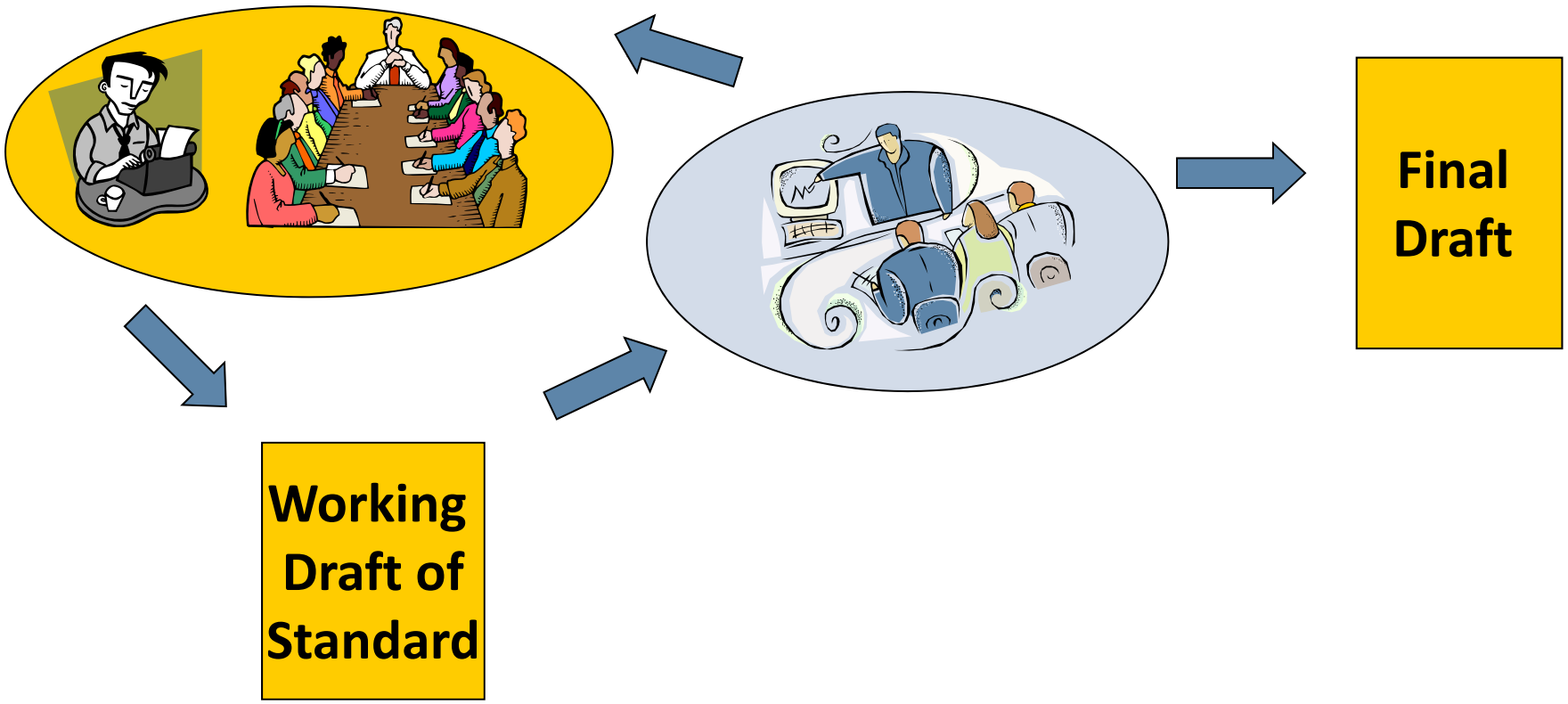
Drafting Team Responses to Comments

If Comment:	Then:	And:
Unrelated	Note that comment is unrelated	No action needed
Proposes change beyond scope	Note that comment is proposing an expansion	Add "issues database"
Proposes modification based on new technical issue	Provide team's analysis of the proposal	If accepted, modify standard
Proposed modification based on already vetted technical issue	Provide summary of vetting and resolution	No action needed
Proposes modification to provide greater clarity	Provide team's view as to whether the proposed modification improves clarity	If accepted, modify the standard

Emphasis on Quality Before Posting Final Drafts

Quality review required before "final" draft posted.

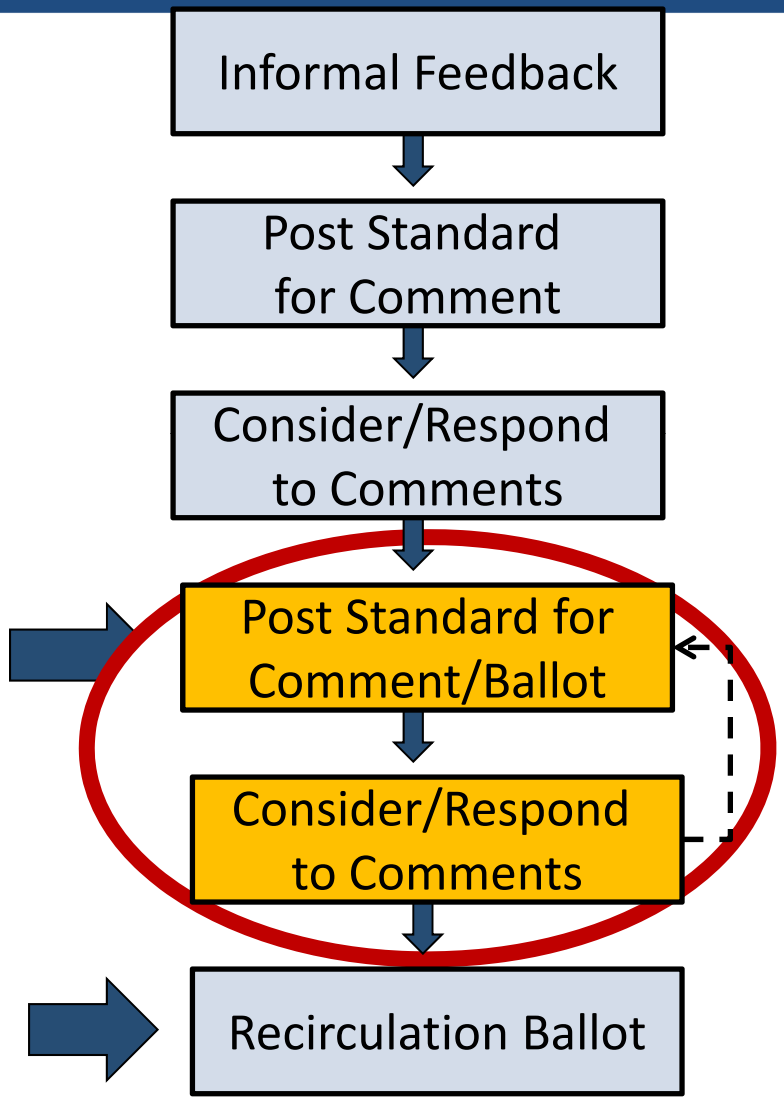
Results of review sent to Standards Committee and drafting team.



Stakeholder Consensus Process

New/Successive Ballot:
At this step, the standard is either "new" or significantly changed from the last version posted for comment/ ballot. The ballot record starts with no votes and no comments.

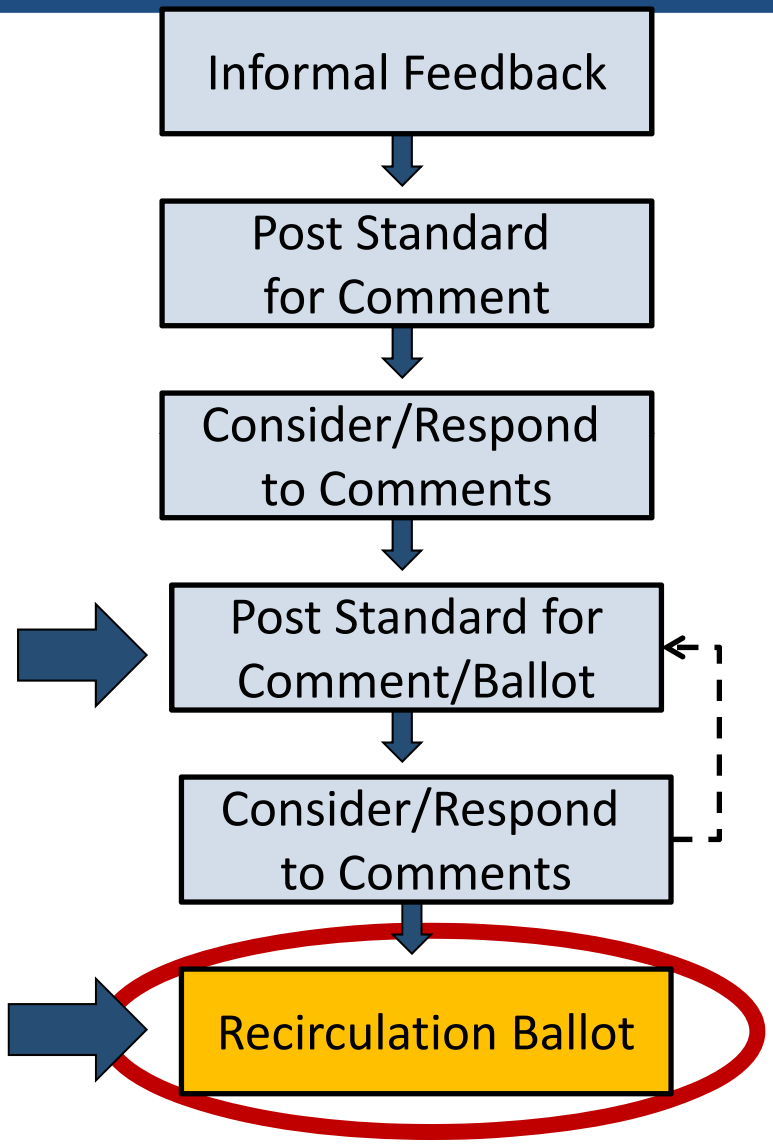
Recirculation Ballot:
At this step, there have been no significant changes to the standard from the last ballot. The ballot record starts with all votes and comments from the previous ballot.



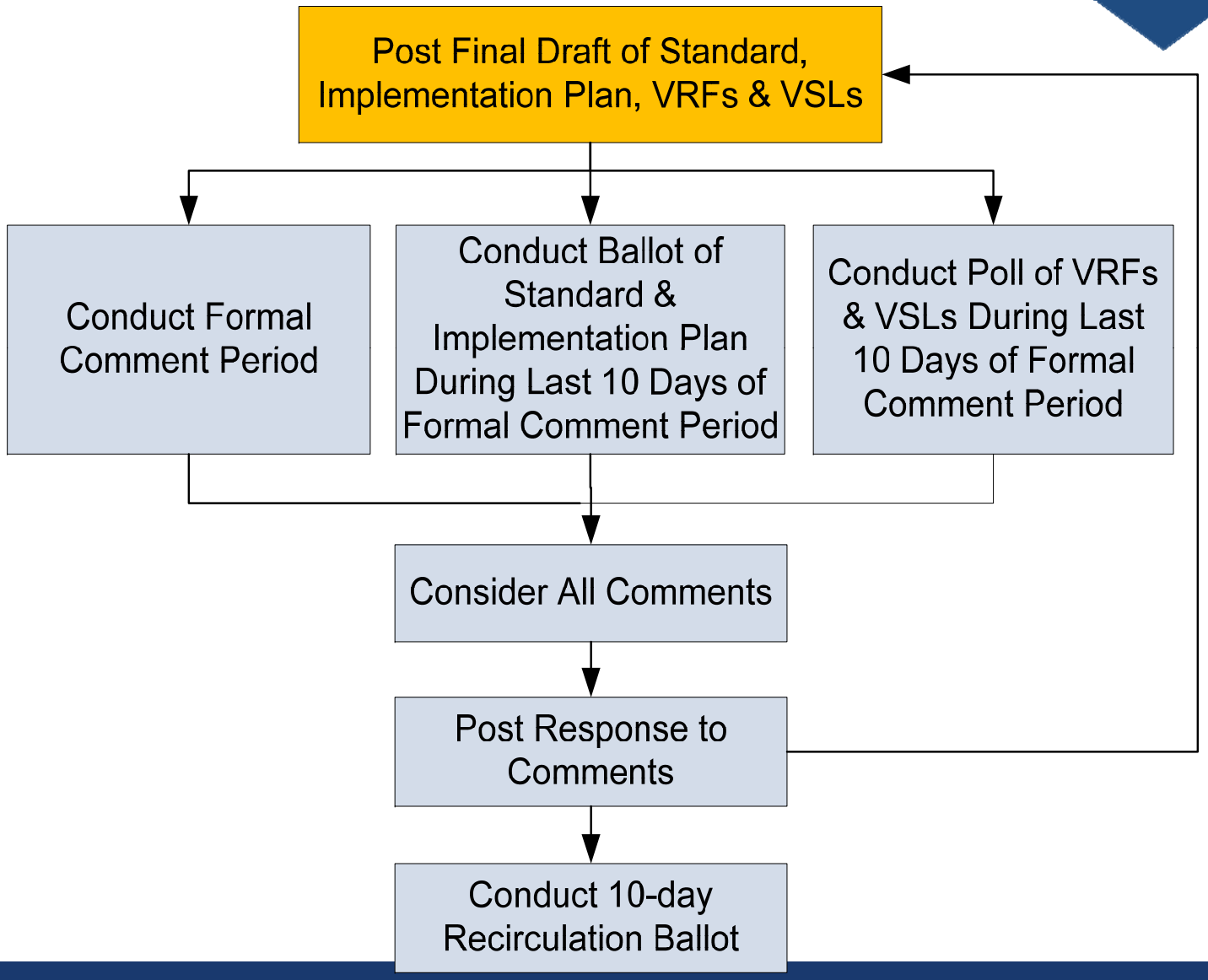
Stakeholder Consensus Process

New/Successive Ballot:
At this step, the standard is either "new" or significantly changed from the last version posted for comment/ ballot. The ballot record starts with no votes and no comments.

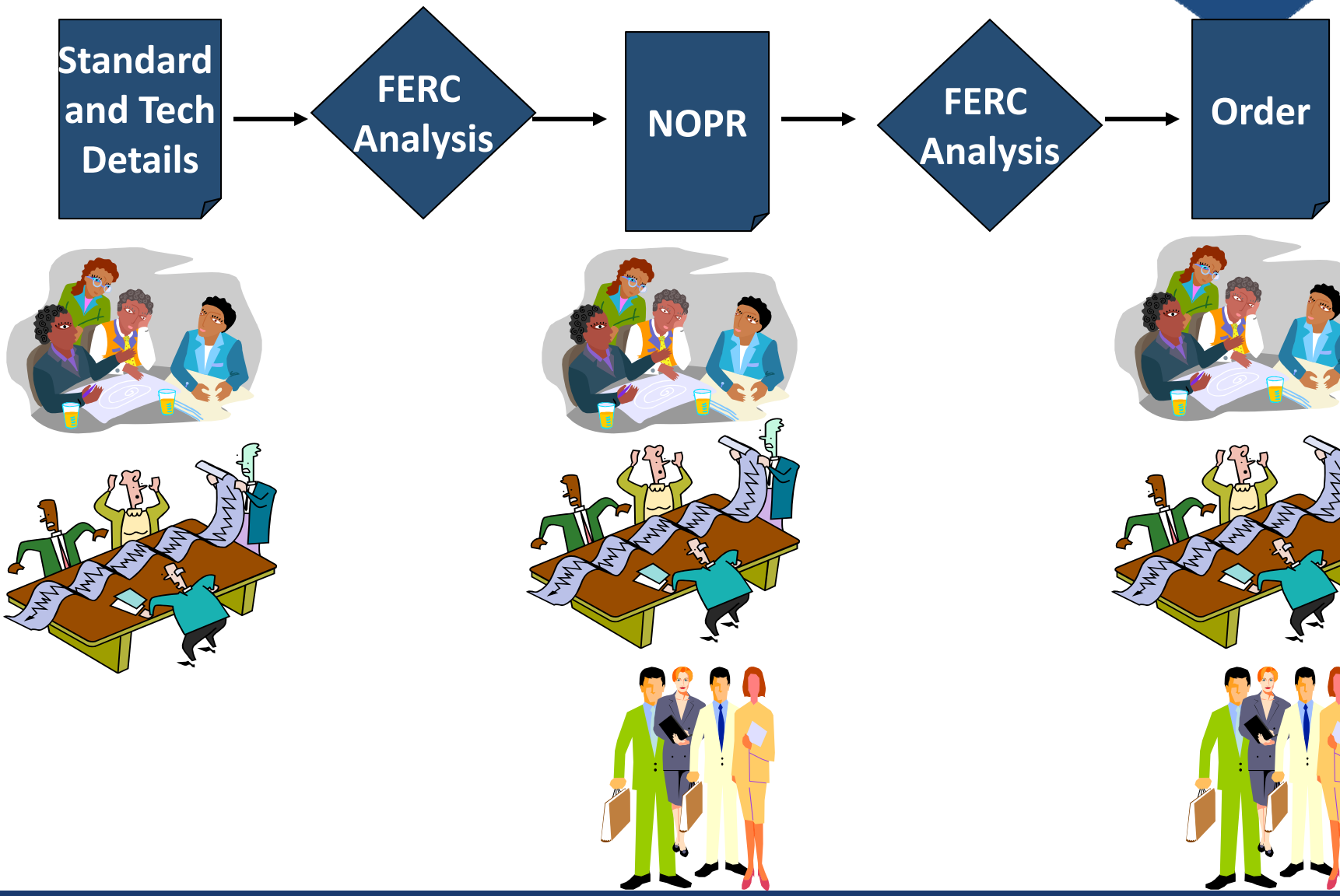
Recirculation Ballot:
At this step, there have been no significant changes to the standard from the last ballot. The ballot record starts with all votes and comments from the previous ballot.



Concurrent Commenting and Balloting



FERC's Approval Process for Standards



Interpretations

- A valid interpretation request seeks additional clarity about one or more requirements in approved NERC Reliability Standards
- An entity or individual may submit a Request for Interpretation using the form on NERC's website
- The interpretation development process is similar to the standard development process
- An interpretation response provides clarity on the requirement(s) but does not expand on the requirement(s) or explain how to comply

Getting Involved

- Add yourself to mailing list for standards by emailing eleanor.crouch@nerc.net
- Respond to requests for comments on draft standards; review comments from others
- Participate in webinars and workshops
- Have your company join the Registered Ballot Body and Ballot Pools
- Vote on standards
- Volunteer for drafting teams
- Volunteer for the Standards Committee



NERC Staff Contacts

- Feedback on the standards process: **Maureen Long** at maureen.long@nerc.net or **Laura Hussey** at laura.hussey@nerc.net or fill out a Suggestions and Comments form.
- Help joining a Registered Ballot Body or participating in comment periods: **Monica Benson** at monica.benson@nerc.net
- To be added to (one or more of) NERC's email lists: **Eleanor Crouch** at eleanor.crouch@nerc.net
- Suggestions for website improvements: **Kristin Iwanechko** at kristin.iwanechko@nerc.net
- Suggestions for improved communication: **Mallory Huggins** at mallory.huggins@nerc.net
- If you ever feel there was an error or omission during the consideration of comments process: **Herb Schrayshuen** at herb.schrayshuen@nerc.net.

Questions?



Other feedback? Contact mallory.huggins@nerc.net.

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

BOARD OF DIRECTORS
Wednesday, November 30, 2011

7:30 a.m. – 10:30 a.m.
Toronto Marriott Bloor Yorkville
90 Bloor Street East
Toronto, Ontario

Dial-In Available: 877-260-3999 **Code: 6945#**

AGENDA

1. Introductions/Quorum/Antitrust Compliance Statement 7:30 a.m.

2. President's Report 7:35 a.m.

3. Consideration of draft NPCC Board of Directors Minutes of October 26, 2011 Meeting 7:45 a.m. *[Action Required]*

4. Membership Sector Designations 7:50 a.m. *[Action Required]*

5. NPCC Committees 8:00 a.m.
   a) Approval of 2012 Corporate Governance and Nominating, Finance and Audit, Management Development and Compensation, and Pension Committee Members *[Action Required]*
   b) Approval of 2012 RSC, CC, RCC, PIC Members *[Action Required]*
   c) Committee Reports – to be presented at 11/30/11 Members Meeting

6. Designation of 2012 Officers for NPCC 8:10 a.m. *[Action Required]*

7. Approval of 2012 NPCC Independent Chairman 8:45 a.m. *[Action Required]*

8. Organizational Matters 9:10 a.m.
   a) MDCC Recommendations
      (Committee Resolutions to be distributed at meeting) *[Action Required]*
   b) Topics for January 31, 2012 Board Strategy Session
      e.g.: Developmental Process for Board Policy Positions, etc.

9. Administrative Matters 9:55 a.m.
   a) Review of 2011 Board Self-Assessment

10. Other Matters 10:10 a.m.
    a) FERC Approval of NPCC as WECC CEA

AGENDA (continued)

11. 2012 Board of Director Meeting Dates 10:25 a.m.
    - Monday, January 31, 2012 – NPCC Board Strategy Session (1 p.m.) and Dinner (6 p.m.)
    - Tuesday, February 1, 2012 – NPCC Offices (8:30 a.m. – 1 p.m.)
    - Tuesday, March 13, 2012 –Tentative BES Teleconference (10 a.m. – 11 a.m.)
    - Tuesday, May 1, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Thursday, June 26, 2012 – NPCC Offices (10 a.m. – 3 p.m.)
    - Tuesday, August 7, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Wednesday, September 19, 2012 – NPCC Offices (10 a.m. – 3 p.m.)
    - Tuesday, October 30, 2012 – Teleconference (10 a.m. – 1 p.m.)
    - Wednesday, November 30, 2012 – Montreal, Quebec (7:30 a.m. – 10 a.m.)

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Northeast Power Coordinating Council, Inc. (NPCC)

Chairman: **Harvey J. Reed**
President and CEO: **Edward A. Schwerdt**
Chief Operating Officer: **Jennifer Budd Mattiello**
Secretary: **Andrianne S. Payson, Esq.**
Treasurer: **Christopher Weir, CPA**

DIRECTORS

SECTOR 1 - TOs
William G. Longhi (O&R)
André Boulanger (HQ TE)

SECTOR 2 - RCs
Peter Brandien (ISO-NE)
Bruce B. Campbell (IESO)
Rick Gonzales (NYISO)

SECTOR 3 – TDUs, Dist., LSEs
David H. Boguslawski (Northeast Utilities)
Michael Penstone (Hydro One)

SECTOR 4 – GOs
Andrew Barrett (OPG)

SECTOR 5 - Marketers
Glen McCartney (CECG)
Matthew J. Picardi (Shell Energy NA)
Daniel Whyte (Brookfield)

SECTOR 7 - Regulatory
Hans Mertens (VT DPS)
Tammy Mitchell (NYS DPS)

SECTOR 8 - Others
Michael Forte (NYSRC)

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

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

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Andrianne S. Payson at 212-259-8218.

NPCC, Inc.

President's Report

November 30, 2011

Board of Directors Meeting

NPCC, Inc.

Report Items:

- Bulk Electric System Definition
- 2011 Board Actions
- ERO Efficiency Efforts

Northeast Power Coordinating Council, Inc. Board of Directors Meeting Draft Minutes for Approval

October 26, 2011 | 10:00 a.m.
(via teleconference)

The Chairman called to order a duly noticed meeting of the Board of Directors ("*Board*") of Northeast Power Coordinating Council, Inc. ("*NPCC*") held on October 26, 2011, at 10:00 a.m. A quorum was declared present during the meeting by the President and CEO, Edward Schwerdt. Andrianne Payson acted as Recording Secretary. The meeting announcement, agenda and list of attendees are attached as **Exhibits A, B, and C**, respectively.

NPCC Antitrust Compliance Guidelines
The Chairman recommended a waiver of the reading of the *NPCC Antitrust Compliance Guidelines* that was distributed via email with the Board agenda package and reviewed by Directors upon commencement of the meeting. A motion to waive the reading of the *NPCC Antitrust Compliance Guidelines* was duly made, seconded and unanimously approved.

Minutes
The President and CEO presented for approval a draft of the minutes of the Board meeting held on September 20, 2011. He noted that a few revisions had been incorporated into the minutes to clarify comments made during the last meeting. A motion to approve the minutes, as modified, of the NPCC Board of Directors meeting held on September 20, 2011 was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

President's Report
The President and CEO presented his report to the Board, which discussed the following three items:

- The President reported that on September 30, 2011, NERC had filed a Petition Requesting Approval of New Enforcement Mechanisms, and Submittal of an Initial Find, Fix and Track ("*FFT*") Informational Finding. He explained that the petition provided for the compliance and enforcement process to be tailored to fit the significance and risk of possible violations, which was an important step toward improving reliability and security of the Bulk Power System. He further explained that NERC and the Regional Entities planned to assist the industry in focusing its energies on developing and maintaining effective internal reliability assurance programs to improve performance. He noted that NPCC had joined with all of the other Regional Entities to file a Motion to Intervene and Comment on October 21st in support of the NERC filing. He explained that the significance of this filing is the recommendation that FERC consider the possible violations that have been resolved through the FFT process as "remediated issues" and should consider these matters closed to further regulatory review.

- The President next provided an update on the extensive efforts being made to develop a workable Bulk Electric System ("*BES*") Definition that is responsive to FERC Orders and supports reliability in the Northeastern United States. He explained that after a 45-day comment period, the recently posted second draft BES Definition had been approved by approximately 72% of the industry, which was more than the 2/3 vote needed to approve the BES definition. He noted that the associated "exceptions" process documentation had been approved by 64% of the industry. He informed the Board that responses to industry comments on both the draft BES Definition and the

"exceptions" process documentation were being developed by the BES drafting teams and that both items would be re-balloted shortly. He added that NPCC was proactive in developing an initial draft template for the industry's BES transition plans and had distributed the draft both within NPCC and NERC for comments.

- The President concluded his report with an update stating that NERC would be announcing a number of substantive changes to the NERC Rules of Procedure in order to simplify and provide more consistency with the application of this document. He noted that the proposed changes are scheduled to be posted for comments next week and that they impact the standards development, compliance enforcement and reliability assessment and performance analysis program areas. He explained that earlier draft versions of the proposed changes codify the new Events Analysis process, seek to impose penalties on the industry for administrative infractions, and potentially revise the role of the enforcement hearing officer in a manner that could inadvertently be inconsistent with NPCC's recently approved "hearing body" structure. He noted that NPCC's policy input to the NERC Member Representatives Committee and NERC Board of Trustees is intended to be directive with respect to these proposed changes, and that the Board policy input on enforcement and reliability assessment and performance analysis program areas would be discussed later in the meeting.

Report by the Treasurer

FAC Charter - The Treasurer presented his report to the Board. He informed the Board that the Finance and Audit Committee (FAC) had recently reviewed the FAC charter and was recommending certain ~~changes~~minor changes. ~~that were~~The Charter is consistent with American Institute of Certified Public Accountants (AICPA) recommendations~~requirements~~. A motion to approve the revised FAC charter was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Third Quarter 2011 Regional Entity (RE) Division Activities - NPCC's Senior Financial Analyst, Ms. Jessica Hala, presented the Statement of Activities (RE Division) for the period ended September 30, 2011 and provided a brief summary of NPCC's financial performance through the end of the third quarter. She explained that funding from assessments, workshops and membership dues were in line with budget year-to-date and that they were projected to remain on budget through year end 2011. She also noted that quarterly remittances from NERC had been received in a timely manner. Ms. Hala informed the Board that total expenses were approximately $2.1 million under-budget year-to-date, but that based on expected fourth quarter activity, total expenses were estimated to remain in line with or somewhat under budget at year end 2011. As examples, she explained that although personnel expenses were under-budget by $1.2 million through the end of third quarter 2011, the accrual for at-risk compensation in the fourth quarter would bring personnel expenses closer to the figure budgeted for calendar year 2011 and that staff vacancies would ultimately bring personnel expenses under the budget by approximately $200,000 at year end, absent any fourth quarter staffing changes. Ms. Hala further explained that contracts and consulting expenses were $582,000 under budget through September 30, 2011, but were projected to be in line with the amount budgeted for this line item for calendar year 2011 due to planned work flow in the Compliance program area in fourth quarter 2011. There were no questions from the Board following this presentation.

Organizational Matters

Corporate Governance and Nominating Committee (CGNC) Independent Director Nominees – The Board Chair presented the CGNC's two independent director nominees for 2012-2014, Mr. Donald L. Correll and Ms. Jan L. Newton, whose biographies had been circulated to the Board prior to the meeting. Following questions from the Board, the Board Chair explained that there was a good selection of candidates and that it was difficult to select two nominees from the top candidates. The President and CEO added that the CGNC had provided Russell Reynolds Associates (RRA) with the criteria that should be used to select candidates and that RRA had developed an extensive listing of candidates meeting the criteria for a North American-wide search. In response to questions from the Board, the Board Chair explained that all other candidates had been notified by RRA regarding the CGNC's decision on their candidacy. One Director

noted that a candidate he had recommended to the CGNC for consideration had not been notified by RRA and asked for follow-up by the CGNC. The President and CEO expressed surprise that RRA had not contacted this candidate and indicated that the Vice President and COO would follow-up immediately with RRA regarding this matter. In response to additional questions from the Board, the President and CEO explained that both Independent Directors would serve the same two-year term from 2012 to 2014, but that subsequent terms could be staggered. He also explained that the compensation for both directors was reviewed for comparability with Independent Director compensation studies discussed within the CGNC, fees paid by NERC and other Regional Entities, the Board Chair's compensation paid by NPCC, and feedback from RRA regarding Independent Director compensation in the sector generally. The President and CEO added that per diem payments would only be required if there was a compliance hearing and the Independent Directors were to serve on the hearing body for a proceeding. A motion to approve the two Independent Director nominees recommended by the CGNC, Mr. Donald L. Correll and Ms. Jan L. Newton, was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Draft Independent Director Agreement - The Board Chair generally explained the form of agreement that had been reviewed by the CGNC and asked for questions. There were no questions from the Board. A motion to approve the draft form of Independent Director Agreement as recommended by the CGNC was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Membership, Board and Committee Changes
Stakeholder Director Nominees - The President and CEO presented the following CGNC recommended Stakeholder Director nominees for 2012:

Sector 1 - Transmission Owners

André Boulanger (1 year term)
Hydro-Quebec TransEnergie

William Longhi (2 year term)
Orange and Rockland Utilities

Sector 2 - Reliability Coordinators

Peter Brandien (1 year term)
ISO-New England, Inc.

Bruce Campbell (2 year term)
Independent Electricity System Operator

Sector 3 - TDUs, Dist., and LSEs

David Boguslawski (1 year term)
Northeast Utilities

Mike Penstone (2 year term)
Hydro One, Inc.

Sector 4 - Generator Owners

Andrew Barrett (1 year term)
Ontario Power Generation, Inc.

Brad Van Auken (2 year term)
New York Power Authority

Sector 5 - Marketers, Brokers, Aggregators

Glen McCartney (1 year term)
Constellation Energy Commodities Group, Inc.

Daniel Whyte (2 year term)
Brookfield Power Generation

Sector 6 - Regulators

Hans Mertens (1 year term)
Vermont Dept. of Public Service

Tammy Mitchell (2 year term)
New York State Dept of Public Service

Sector 7 – Subregional, Customers, Other Regional Entities

Michael Forte (1 year term)
New York State Reliability Council, LLC

Jeffrey Fenn (2 year term)
SGC Engineering

The President and CEO explained that since the NPCC Bylaws provide for staggered terms for Stakeholder Directors, the first Stakeholder Director nominee in each Sector would serve a one-year term and the second Stakeholder Director nominee in the Sector would serve a two-year term. He noted that the CGNC's recommendation for addressing representation in Sector 3, where there were three existing Board members who had expressed interest in serving, was that nominee Peter Brandien would serve a one-year term while another Reliability Coordinator representative, such as Mr. Rick Gonzales, could serve a subsequent one-year term. There were no additional questions from the Board. A motion to endorse the slate of stakeholder director nominees to be presented to Members for approval was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Committee Changes – The President and CEO informed the Board that there were several proposed changes to NPCC's Regional Standards Committee (RSC) and Reliability Coordinating Committee (RCC), and that two previously proposed changes by NYPA had been withdrawn. The Board noted the following committee changes:

- RSC - Sector 2 (*Reliability Coordinators*): Ms. Tina Teng to serve as the Independent Electricity System Operator member, replacing Mr. Kurtis B. Chong.
- RSC - Sector 2 (*Reliability Coordinators*): Mr. Scott Berry to serve as the Independent Electricity System Operator alternate #1.
- RSC - Sector 2 (*Reliability Coordinators*): Ms. Esther Kim to serve as the Independent Electricity System Operator alternate #2.
- RCC - Sector 2 (*Reliability Coordinators*): Mr. Len Kula to serve as the Independent Electricity System Operator alternate, replacing Mr. Mark Wilson.

- RCC - Sector 2 (*Reliability Coordinators*): Mr. Paul Renaud to serve as the Vermont Transco member, replacing Mr. Frank Ettori.
- RSC – Sector 3 (*TDUs, Dist., LSEs*): Mr. Anthony LaRusso to serve as the National Grid alternate.

A motion to approve these committee changes was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

NERC Matters

MRC and BOT November 2-3, 2011 Agendas – The President and CEO informed the Board that the NERC Board Chair was soliciting input for the upcoming NERC Member Representatives Committee meeting and the NERC Board of Trustees meeting on November 2 and 3, 2011. He presented the draft NPCC Board Policy Input for these meetings and requested comments from the Board on five areas: (1) Compliance Enforcement Initiative; (2) Compliance Application Notices (CAN) – Status; (3) Status of CIP Standards Version 4 and 5 Implementation Plans; (4) Bulk Electric System (BES) Definition and Rules of Procedure – Status; and (5) Rules of Procedure Changes. Several Board members provided comments on the draft Board Policy Input relating to (i) the "no formulaic criteria for FFT designation"; (ii) the authority of FERC to approve FFTs in the United States; (iii) the addition of a "cost effectiveness" comment to item 4 (BES Definition); (iv) the "negative" vote by a majority of NPCC Members against the proposed BES Definition; and (v) the "affirmative vote by the NPCC Board in support of the proposed BES Definition. Following a lengthy discussion, the Board agreed to revise item 4 (BES Definition) of the NPCC Board Policy Input so that it reads as follows:

a. NPCC members have separately submitted their individual comments with regard to the BES Definition
b. NPCC acknowledges the proposed NERC BES Definition as being responsive to the FERC Order and reiterates its view that cost effectiveness should be a consideration in the implementation, including in the exception process
c. NPCC, consistent with its commitment to enhanced reliability, will continue to utilize a risk-based analysis to define facilities for which its more stringent Regional criteria apply

A motion to approve the draft NPCC Board Policy Input, as modified by the Directors, was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Following the discussion on the draft NPCC Board Policy Input, several Board members expressed concern that NPCC Members could vote one way on a particular issue while the NPCC Board voted another way on that same issue. One Director noted that the Board did not always have to share the same position as NPCC Members on a particular issue and that NPCC management was not required to "line up the organization's views with those of the Members all of the time." Directors also noted that NPCC, as an organization, could be effective if it solicits feedback from its Members but is able to make an independent decision. In response to additional questions from the Board, the Board Chair suggested that the question of who the Board represents and whether the Board can act independently, pursuant to the NPCC Bylaws, should be placed on the agenda for the 2012 Board Strategy Meeting. The President and CEO agreed to add this item to the 2012 Board Strategy Meeting agenda.

Administrative Matters

Board Charter – The Secretary presented the draft Board of Directors Charter and Governance Guidelines and explained that most of the changes reflected the proposed changes to NPCC's Amended and Restated Bylaws for NPCC's new governance structure. In response to a Director question on the procedure to "retire regionally-specific standard" as the NERC continent-wide standards develop, the President and CEO explained that NPCC Members could vote to eliminate NPCC's regionally-specific standards pursuant to

the NPCC Bylaws. A motion to approve the revised Board of Directors Charter and Governance Guidelines was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

CGNC Charter – The President and CEO then presented the draft CGNC charter which was revised to reflect the addition of independent directors to the NPCC Board and to clarify the process for selecting independent directors and an independent Board Chair. A motion to approve the revised CGNC charter was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Management Development and Compensation Committee (MDCC) Charter – The Board Chair then presented a draft of the MCC charter which had been revised for consistency with NPCC's bylaws, and to incorporate references to the succession plan reviewed by the committee. A motion to approve the revised MDCC charter was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Pension Committee Charter – The President and CEO then presented the draft Pension Committee charter which had been revised to recognize the authority of the Pension Committee to retain advisors that report to the Pension Committee. One Director questioned the authority of the committee to appoint advisors in its sole discretion. Following discussion, it was agreed that the Pension Committee could appoint advisors, but "within the approved budget." A motion to approve the Pension Committee charter, as revised by the Board, was duly made, seconded and unanimously approved.

Proposed 2012 Board of Director Meeting Dates – The President and CEO presented the schedule of proposed Board meeting dates in 2012. At the request of one Director, the Board agreed to change the date of the September meeting in NPCC offices from Tuesday, September 18, 2012 to Wednesday, September 19, 2012. A motion to approve the schedule of Board meeting dates in 2012, as revised, was duly made, seconded and unanimously approved by the Directors in each active Sector of the Board.

Development of 2011 Board of Directors Self-Assessment – The Board Chair questioned whether there were any comments on the CGNC recommended 2011 Board Effectiveness Self-Assessment Questionnaire that was included in the Board agenda package. Since there were no comments during the meeting, he asked the Directors to send their completed questionnaires to the NPCC Secretary. The President and CEO indicated that he would circulate a clean version of the questionnaire to the Board following the meeting since the version circulated to the Board incorporated a few updates in a marked version of the document.

Regulatory Matters

The President and CEO informed the Board that on October 17, 2011 FERC had approved NPCC's Amended & Restated Bylaws which, among other things, established a hybrid board of directors with both stakeholder directors and independent directors. He also informed the Board that a FERC Order had been issued on October 20, 2011 approving NPCC's Protection and Control regional Reliability Standard PRC-002-NPCC-01. The Board recognized the efforts of NPCC's RSC and its chair, Mr. Guy Zito, for this accomplishment that reflected NPCC's first FERC-approved Regional Reliability Standard. One Board member further commended NPCC and the RSC since FERC had also not placed any conditions on this Reliability Standard. The President and CEO concluded his updates on Regulatory Matters by announcing an upcoming FERC technical conference from November 29-30 on reliability.

Future Meetings in 2011

The President and CEO presented the schedule of Board meetings for the remainder of calendar year 2011, which was distributed with the Board agenda package. He reminded the Board that the next Board meeting was scheduled for November 30, 2011 from 7:30 a.m. to 10:30 a.m., in Toronto, Ontario.

The President and CEO also reminded the Board that NPCC's 2011 Annual General Meeting was scheduled for Wednesday, November 30, 2011 from 1:00 pm to 5:00 pm, in Toronto, Ontario.

Adjournment
There being no further business, the Board Chair adjourned the meeting of the NPCC Board of Directors at 11:50 a.m.

Approved by Board action on _____, 2011.

Submitted by,

_____
Andrianne S. Payson
NPCC Secretary

EXHIBIT C
LIST OF ATTENDEES
October 26, 2011
(via teleconference)

Present:	Harvey J. Reed, Chairman Edward A. Schwerdt, President and CEO Jennifer Budd Mattiello, Vice President and COO Christopher Weir, CPA, Treasurer Andrianne S. Payson, Esq., Secretary And the following members of the Board of Directors:
Sector 1 (TOs)	William G. Longhi, Orange & Rockland Utilities André Boulanger, Hydro-Québec TransÉnergie
Sector 2 (RCs)	Peter Brandien, ISO New England, Inc. Bruce B. Campbell, Independent Electricity System Operator Rick Gonzales, New York Independent System Operator, Inc. (by proxy to the President)
Sector 3 (TDUs, DCs, LSEs)	Michael Penstone, Hydro One David Boguslawski, Northeast Utilities
Sector 4 (GOs)	Andrew Barrett, Ontario Power Generation, Inc.
Sector 5 (Marketers, Brokers and Aggregators)	Glen McCartney, Constellation Energy Commodities Group, Inc. Daniel Whyte, Brookfield Power Generation (by proxy to the President)
Sector 6 (Customers)	–
Sector 7 (Regulatory)	Hans Mertens, Vermont Department of Public Service Tammy Mitchell, NYS Department of Public Service
Sector 8 (Others)	Michael Forte, New York State Reliability Council, LLC
Guests	Jessica Hala, NPCC Senior Financial Analyst

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Approval of

Northeast Power Coordinating Council, Inc. (NPCC)

Corporate Governance and Nominating Committee, Finance and Audit Committee, Management Development and Compensation Committee, and Pension Committee Members for 2012

****

Corporate Governance and Nominating Committee for 2012

Harvey Reed, Chair	Chairman of the Board
Andrew Barrett	Board Director
Glen McCartney	Board Director
OPEN	Board Director
Edward A. Schwerdt	President and CEO
Andrianne Payson	Secretary (Non-voting)

Finance and Audit Committee for 2012

Christopher Weir, CPA, Chair	Treasurer
Peter Brandien	Board Director
Bruce B. Campbell	Board Director
Daniel Whyte	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrianne Payson	Secretary (Non-voting)

Management Development and Compensation Committee for 2012

Harvey J. Reed, Chair	Chairman of the Board
Peter Brandien	Board Director
William G. Longhi	Board Director
OPEN	Board Director
Andrew J. Fawbush	Assistant Secretary (Non-voting)

Pension Committee for 2012

Edward A. Schwerdt, Chair	President and CEO
Robert J. DeAngelo	Assistant Treasurer (Northeast Utilities)
Michael Forte	Board Director
Hans Mertens	Board Director
Michael Penstone	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrew J. Fawbush	Assistant Secretary (Non-voting)

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Approval of

Northeast Power Coordinating Council, Inc. (NPCC)

Corporate Governance and Nominating Committee, Finance and Audit Committee, Management Development and Compensation Committee, and Pension Committee Members for 2012

****

Corporate Governance and Nominating Committee for 2012

Harvey Reed, Chair	Chairman of the Board
Andrew Barrett	Board Director
Glen McCartney	Board Director
OPEN	Board Director
Edward A. Schwerdt	President and CEO
Andrianne Payson	Secretary (Non-voting)

Finance and Audit Committee for 2012

Christopher Weir, CPA, Chair	Treasurer
Peter Brandien	Board Director
Bruce B. Campbell	Board Director
Daniel Whyte	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrianne Payson	Secretary (Non-voting)

Management Development and Compensation Committee for 2012

Harvey J. Reed, Chair	Chairman of the Board
Peter Brandien	Board Director
William G. Longhi	Board Director
OPEN	Board Director
Andrew J. Fawbush	Assistant Secretary (Non-voting)

Pension Committee for 2012

Edward A. Schwerdt, Chair	President and CEO
Robert J. DeAngelo	Assistant Treasurer (Northeast Utilities)
Michael Forte	Board Director
Hans Mertens	Board Director
Michael Penstone	Board Director
Jennifer Budd Mattiello	Vice President and COO
Andrew J. Fawbush	Assistant Secretary (Non-voting)

APPROVAL OF
REGIONAL STANDARDS COMMITTEE
2011

Chairman:

Guy V. Zito - Assistant Vice President - Standards
Northeast Power Coordinating Council, Inc
Tel. (212) 840-1070
Fax (212) 302-2782
Email: gzito@npcc.org

Co-Vice Chairman:

Gregory A. Campoli -Supervisor, Reliability Compliance & Assessment
New York Independent System Operator
Tel. (518) 356-6159
Fax (518) 356-6118
Email: gcampoli@nyiso.com

Co-Vice Chairman:

Michael R. Lombardi – Senior Engineer, Reliability Compliance
Northeast Utilities
Tel. (860) 665-6619
Fax (860) 665-2322
Email: lombardir@nu.com

Sector (1) – <u>Transmission Owners</u>

David Kiguel – Manager, Reliability Standards
Hydro One Networks Inc.
Tel. (416) 345-5313
Fax (416) 345-4141
Email: david.kiguel@hydroone.com

Christopher L. de Graffenried - Senior Engineer Transmission Planning
Consolidated Edison Company of New York, Inc
Room 1450-S
Tel. (212) 460-2925
Fax (212) 529-4542
Email: degraffenriedc@coned.com

Michael Schiavone - Manager - Control Center, NY
National Grid
Tel. (315) 460-2472
Fax (315) 460-2494
Email: Michael.Schiavone@us.ngrid.com

Randy MacDonald, P. Eng. - Senior Power System Engineer
New Brunswick Power Transmission
Tel. (506) 458-4653
Fax (506) 458-3536
Email: ramacdonald@nbpower.com

REGIONAL STANDARDS COMMITTEE

(Continued)

Robert J. Pellegrini - ES Asset Management
Manager Protection &Control/ SCADA
The United Illuminating Company
801 Bridgeport Avenue
Shelton, Connecticut 06484
Tel. (203) 499-2413
Fax (203) 926-4664
Email: Robert.pellegrini@uinet.com

Sylvain Clermont - Manager Neighboring Systems
Hydro-Quebec TransÉnergie
Tel. (514) 879-4648
Fax (514) 879-4685
Email: clermont.sylvain@hydro.qc.ca

Michael R. Lombardi – Senior Engineer, Reliability Compliance
Northeast Utilities
Tel. (860) 665-6619
Fax (860) 665-2322
Email: lombardir@nu.com

Ben Wu - Transmission & Substation Engineering
Orange & Rockland Utilities, Inc.
Tel. (845) 577-3713
Fax (845) 577-3720
Email: WUB@oru.com

Sector (2) – <u>Reliability Coordinators</u>

Donald Weaver
New Brunswick System Operator
Tel. (506) 458-4640
Fax (506) 458-4626
Email: donald.weaver@nbso.ca

Gregory A. Campoli -Supervisor, Reliability Compliance & Assessment
New York Independent System Operator
Tel. (518) 356-6159
Fax (518) 356-6118
Email: gcampoli@nyiso.com

Kathleen M. Goodman – Senior Operations Compliance Coordinator
ISO New England, Inc.
Tel. (413) 535-4111
Fax (413) 535-4343
Email: kgoodman@iso-ne.com

REGIONAL STANDARDS COMMITTEE

(Continued)

Tina Teng - Engineer/Technical Officer
Independent Electricity System Operator
Tel. (905) 855-6121
Fax (905) 855-6407
Email: tina.teng@ieso.ca

Si Truc Phan
TransÉnergie (Hydro-Quebec)
2 Complexe Desjardins, Ground floor, East Tower
Montreal, Québec, Canada H5B 1J7
Tel. (514) 879-4100 X5446
Fax (514) 879-4487
Email: phan.si_truc@hydro.qc.ca

Sector (3) – Transmission Dependent Utilities ("TDUs"); Distribution Companies & Load-Serving Entities ("LSEs")

Peter Yost – Manager, Standards & Compliance
Consolidated Edison Company of New York, Inc
Tel. (212) 460-2889
Fax (212) 529-1130
Email: yostp@coned.com

Saurabh Saksena - Engineer, Reliability Compliance
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-3226
E-mail: Saurabh.saksena@us.ngrid.com

Sector (4) – Generator Owners

Wayne Sipperly - NERC Reliability Compliance Program Manager
New York Power Authority
Tel. (914) 287-3753
Email: wayne.sipperly@nypa.gov

Mike Garton –Electric Market Policy Manager
Dominion Resources Services, Inc.
120 Tredegar Street, RS-6th
Richmond, VA 23219
Tel. (804) 819-2336
Email: mike.garton@dom.com

REGIONAL STANDARDS COMMITTEE

(Continued)

David Ramkalawan P.Eng. - Senior Regulatory Analyst
Ontario Power Generation, Inc.
Tel. (416) 592-6089
Fax (416) 592-8519
Email: david.ramkalawan@opg.com

Chantel Haswell – Compliance Specialist
FPL Group, Inc.
Tel. (561) 694-3129
Fax (561) 694-3177
Email: chantel.haswell@fpl.com

Sector (5) – Marketers, Brokers & Aggregators

Bruce Metruck - Manager Compliance & Standards
New York Power Authority
F.R. Clark Energy Center
6520 Glass Factory Road
Marcy, NY 13403
Tel. (315) 792-8213
Fax (315) 792-8401
Email: bruce.metruck@nypa.gov

Brian Evans-Mongeon – President/CEO
Utility Services, Inc.
Tel. (802) 552-4022
Fax (866) 214-8632
Email: brian.evans-mongeon@utilitysvcs.com

Sector (6) – State and Provincial Regulatory and/or Governmental Authorities

Diane J. Barney – Planning Engineer
State of New York
Public Service Commission
Department of Public Service
Tel. (518) 486-2943
Fax (518) 473-2420
Email: Diane_barney@dps.state.ny.us

Sector (7) – Sub-Regional Reliability Councils, Others and Customers

Alan Adamson - Consultant
New York State Reliability Council, LLC
1907 Evva Drive
Schenectady, NY 12303
Tel/Fax (518) 355-1937
Email: aadamson@nycap.rr.com

REGIONAL STANDARDS COMMITTEE

(Continued)

ALTERNATES

Sector (1) – Transmission Owners

Ajay Garg, P. Eng - Manager, Policy & Approvals
Hydro One Networks, Inc.
Tel. (416) 345-5420
Fax (416) 345-4141
Email: Ajay.Garg@HydroOne.com

Sector (2) – Reliability Coordinators

Scott Berry - Senior Engineer/Technical Officer (Alternate #1)
Independent Electricity System Operator
Tel. (905) 403-6912
Fax (905) 855-6407
Email: scott.berry@ieso.ca

Esther Kim – Engr./Technical Officer – Registration & Compliance (Alternate #2)
Support, Market Facilitation
Independent Electricity System Operator
Tel. (905) 855-6488
Fax (905) 855- 6129
Email: esther.kim@ieso.ca

Sector (3) – Transmission Dependent Utilities ("TDUs"); Distribution Companies & Load-Serving Entities ("LSEs")

Anthony LaRusso – Reliablity Standards Engineer
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
Tel. (781) 907-3226
Email: Anthony.LaRusso@us.ngrid.com

Sector (4) – Generator Owners

Saul Rojas - NERC Program Compliance Manager
New York Power Authority
Tel. (914) 681-6661
Email: saul.rojas@nypa.gov

REGIONAL STANDARDS COMMITTEE

(Continued)

Sector (5) – <u>Marketers, Brokers & Aggregators</u>

Daniella Piper - Reliability Standards & Compliance Engineer
New York Power Authority
Tel. (914) 681-6595
Fax (914) 681 6534
Email: daniella.piper@nypa.gov

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

APPROVAL OF COMPLIANCE COMMITTEE MEMBERS 2012

Chairman

Stanley Kopman
Assistant Vice President – Compliance Registration and Enforcement
NPCC
(Voice) 212-840-4710
(Fax) 212-302-2782
skopman@npcc.org

Vice Chair

Peter Yost
Manager, Standards and Compliance
Consolidated Edison Company of New York, Inc.
(Voice): 212-460-2889
(Fax): 212-529-1130
yostp@coned.com

Sector (1) - Transmission Owners

Ajay Garg
Engineer, Reliability Standards
Hydro One Networks Inc.
(Fax): 416-345-4141
ajay.garg@hydroone.com

William Temple
Program Manager
Northeast Utilities
(Voice): 860-665-3908
(Fax): 860-665-2322
templwj@nu.com

Sylvain Clermont
Hydro-Quebec TransEnergie
(Voice): 514-879-4648
(Fax)**:** 514-289-5417
clermont.sylvain@hydro.qc.ca

COMPLIANCE COMMITTEE MEMBERS

(CONTINUED)

Edward F. Dahill, P.E.
Lead Engineer
National Grid
(Voice): 781-907-2443
(Fax): 781-907-5706
edward.dahill@us.ngrid.com

Peter Yost
Manager, Standards and Compliance
Consolidated Edison Company of New York, Inc.
(Voice): 212-460-2889
(Fax): 212-529-1130
yostp@coned.com

Kim Moulton
Compliance Program Specialist
VELCO
366 Pinnacle Ridge Road
Rutland, VT 05753
(Voice): 802-770-0623
kmoulton@velco.com

Edward Bedder
Compliance Program Manager
Orange and Rockland Utilities Inc.
390 West Route 59
Spring Valley NY 10977
(Voice): 845-577-3827
(Cell): 917-681-8129
beddere@oru.com

Jonathan Appelbaum
Director, NERC
The United Illuminating Company
157 Church Street
New Haven, CT 06506
(Voice): 203-499-2645
jonathan.appelbaum@uinet.com

John Robertson
Manager NERC Compliance
NSTAR Electric
One NSTAR Way
Westwood, MA 02090
(Voice): 781-441-8455
john.robertson@nstar.com

COMPLIANCE COMMITTEE MEMBERS

(CONTINUED)

Sector (2) - Reliability Coordinators

Calvin Duncan, P.E.
Senior Compliance Engineer
New Brunswick System Operator
(Voice)**:** 506-458-3176
(Fax): 506-458-4626
calvin.duncan@nbso.ca

Gregory Campoli
Supervisor, Reliability Compliance and Assessment
New York Independent System Operator
(Voice)**:** 518-356-6159
(Fax)**:** 518-356-6118
gcampoli@nyiso.com

Richard Burke
Principal Analyst, Reliability & Operations Compliance
ISO-New England, Inc.
(Voice): 413-540-4414
(Fax): 413-535-4343
rwburke@iso-ne.com

Joseph Fox
Conseiller conformité du réseau
Contrôle et Exploitation du réseau
Hydro-Québec TransÉnergie
(Voice): 514-879-4100 #3611
(Fax): 514-879-4691
fox.joseph@hydro.qc.ca

Esther Kim
Engineer, Reliability Standards and Assessments
Independent Electricity System Operator
(Voice): 905-855-6488
esther.kim@ieso.ca

COMPLIANCE COMMITTEE MEMBERS

(CONTINUED)

Sector (3) - Transmission Dependent Utilities ("TDUs"), Distribution Companies, and Load-Serving Entities ("LSEs")

Vicki M. O'Leary
FERC Compliance Manager
National Grid
(Voice): 781-907-2421
(Fax): 781-907-5707
vicki.oleary@us.ngrid.com

Ben Wu
Transmission & Substation Engineering
Orange & Rockland Utilities, Inc.
(Voice): 845-577-3713
(Fax): 845-577-3720
wub@oru.com

Sector (4) - Generator Owners

Thomas Czerniewski
Senior Staff Engineer
Entergy Services, Inc.
(Voice): 914-272-3368
(Fax): 914-272-3537
tczerni@entergy.com

Chantel Haswell
NERC Corporate Compliance
NextEra Energy Resources, LLC
700 Universe Blvd
Juno Beach, FL 33408
(Voice): 561-694-3129
chantel.haswell@fpl.com

Mike Garton
Electric Market Policy Manager
Dominion Resources Services, Inc.
120 Tredegar Street
Richmond, VA 23219
RS-6th
(Voice): 804-819-2336
(Cell): 804-551-0721
mike.garton@dom.com

COMPLIANCE COMMITTEE MEMBERS

(CONTINUED)

Sector (5) - Marketers, Brokers and Aggregators

Bruce Metruck
Manager, Reliability Standards and Compliance
New York Power Authority
(Voice): 315-792-8213
(Fax): 315-792-8401
bruce.metruck@nypa.gov

Brian Evans-Mongeon
President/CEO
Utility Services, Inc.
(Voice): 802-552-4022
(Fax): 802-552-4595
brian.evans-mongeon@utilitysvcs.com

Sector (6) - Customers

To Be Determined

Sector (7) - State and Provincial Regulatory and/or Governmental Authorities

Randy D. Crissman
Vice President – Technical Compliance
Power Supply Business Group
New York Power Authority
(Voice)**:** 914-681-6471
randy.crissman@nypa.gov

Sector (8) - Sub-Regional Reliability Councils, other Regional Entities and Interested Entities

To Be Determined

COMPLIANCE COMMITTEE MEMBERS

(CONTINUED)

Alternates

Sector (1) - Transmission Owners

Chris de Graffenried
Senior Engineer
Consolidated Edison Company of New York, Inc.
(Voice): 212-460-2925
(Fax): 212-529-1130
degraffenriedc@coned.com

Mark Atkins
Compliance Program Engineer
VELCO
366 Pinnacle Ridge Road
Rutland, VT 05753
(Voice): 802-770-6245
(Mobile): 802-353-9347
matkins@velco.com

David Burke
Sr. Specialist - Compliance Program
Orange and Rockland Utilities Inc.
390 West Route 59
Spring Valley NY 10977
(Voice): 845-577-3076
(Cell): 516-523-3711
burkeda@oru.com

Mike Lombardi
Senior Engineer
Northeast Utilities
(Voice): 860-665-6619
lombamr@nu.com

David Kiguel, P. Eng.
Manager, Reliability Standards
Hydro One Networks Inc.
(Voice): 416-345-5313
(Fax): 416-345-4141
david.kiguel@hydroone.com

COMPLIANCE COMMITTEE MEMBERS

(CONTINUED)

Michael Bilheimer
NERC Complinace Analyst
The United Illuminating Company
157 Church Street
New Haven, CT 06506
(Voice): 203-499-2645
michael.bilheimer@uinet.com

Sector (2) - Reliability Coordinators

Scott Berry
Senior Engineer/Technical Officer
Independent Electricity System Operator
(Voice): 905-403-6912
scott.berry@ieso.ca

Tina Teng
Engineer/Technical Officer
Independent Electricity System Operator
(Voice): 905-855-6121
tina.teng@ieso.ca

Matthew Goldberg
Director of Reliability & Operations Compliance
ISO-New England, Inc.
(Voice): 413-535-4029
(Fax): 413-535-4050
mgoldberg@iso-ne.com

Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

Michael Jones
Lead Analyst, Reliability Compliance
National Grid
40 Sylvan Road
Waltham, MA 02451
(Voice): 781-907-2404
michael.jones@us.ngrid.com

COMPLIANCE COMMITTEE MEMBERS

(CONTINUED)

Sector (4) – Generator Owners

Michael Gildea
Director – NERC Compliance
Dominion Resources Services
(Voice): 804-273-4624
(Fax): 804-273-2927
michael.gildea@dom.com

Brian J. Murphy
NERC Corporate Compliance
NextEra Energy Resources, LLC
700 Universe Blvd
Juno Beach, FL 33408
(Voice): 305-442-5132
brian.j.murphy@fpl.com

Sector (5) - Marketers, Brokers and Aggregators

Wayne Sipperly
NERC Reliability Standards Compliance Program Manager
123 Main Street
White Plains, New York 10601
New York Power Authority
Tel. (914) 287-3757
Email: wayne.sipperly@nypa.gov

Sector (7) – State and Provincial Regulatory and/or Governmental Authorities

Saul Rojas
NERC Reliability Standards Compliance Program Manager
123 Main Street
White Plains, New York 10601
New York Power Authority
Tel. (914) 287-6661
Email: saul.rojas@nypa.gov

NPCC, Inc.

APPROVAL OF
2012 RELIABILITY COORDINATING COMMITTEE

Chairman: Donald L. Gates - Manager, Reliability and Operations Services
ISO-New England, Inc.
Tel. (413) 535-4350
Fax (413) 535-4050
Email: dgates@iso-ne.com

Co-Vice Chairman: Michael Schiavone – Manager – Control Center, NY
National Grid
Tel. (315) 460-2472
Fax (315) 460-2494
Email: Michael.Schiavone@us.ngrid.com

Co-Vice Chairman: Alden Briggs – Senior Director, Power System Engineering
New Brunswick System Operator
Tel. (506) 458-4479
Fax (506) 458-3920
Email: alden.briggs@nbso.ca

Sector 1 - Transmission Owners

New Brunswick Power Transmission Corporation
Tony O'Hara, Executive Director
Tel. (506) 458-6703
Fax
Email: TOHara@NBPower.com

Alternate
Randy MacDonald
Tel. (506) 458-4653
Cell (506) 470-3536
Email: RaMacDonald@NBPower.com

Central Maine Power Company
Brian Conroy - Manager - Dispatch & ECC
Tel. (207) 626-9801
Fax (207) 626-6522
Email: brian.conroy@cmpco.com

Alternate
David Conroy – Manager of System Planning
Tel. (207) 626-9750
Fax (207) 623-7380
Email: david.conroy@cmpco.com

National Grid USA
Michael Schiavone – Director, Transmission Control Center - New York
Tel. (315) 460-2472
Fax (315) 460 2494
Email: Michael.Schiavone@us.ngrid.com

NPCC, Inc.

Sector 1 - Transmission Owners
(continued)

The United Illuminating Company
Robert J. Pellegrini - ES Asset Management Process Owner Protection & Control/ Substation
Tel. (203) 499-2413
Fax (203) 926-4664
Email: Robert.pellegrini@uinet.com

Alternate
Jonathan Appelbaum – Director, NERC Compliance
Tel. (203) 499-2645
Fax
Email : jonathan.appelbaum@uinet.com

Vermont Electric Power Company, Inc.
Paul Renaud – Director of Planning and Engineering
Tel. (802) 770-6298
Fax (802) 770-6449
Email: prenaud@velco.com

Alternate
Hantz A. Présumé – Team Lead, System Planning
Tel. (802) 770-6219
Fax (802) 770-6440
Email : Hpresume@velco.com

Central Hudson Gas & Electric Corporation
Thomas C. Duffy – Senior Director, Reliability Compliance
Tel. (845) 486-5417
Fax (845) 486-5894
Email: tduffy@cenhud.com

Consolidated Edison Company of New York, Inc.
Michael Forte – Chief Engineer of Transmission Planning
Tel. (212) 460-3416
Fax (917) 534-4042
Email: fortem@coned.com

Alternate
Peter Yost – Manager, Standards & Compliance
Tel. (212) 460-2889
Fax (212) 529-1130
Email: yostp@coned.com

Long Island Power Authority
David Clarke
Tel. (516) 876-4024
Fax
Email: dclarke@lipower.org

Northeast Utilities
Brad Bentley – Director, Transmission System Planning
Tel. (860) 665-6371
Fax (860) 665-6719
Email: bentlbp@nu.com

NPCC, Inc.

Sector 1 - Transmission Owners
(continued)

New York Power Authority
Steve DeCarlo – Senior Vice President
Transmission
Tel. (315) 792-8236
Fax (315) 792- 8332
Email: steve.decarlo@nypa.gov

Alternate
Michael Parisi – Deputy Director
System Operations
Tel. (315) 792-8207
Fax (315) 792-8401
Email: Mike.Parisi@nypa.gov

New York State Electric & Gas Corp.
Raymond Kinney – Manager, Program/Projects
Electric Transmission Services
Tel. (607) 762-4321
Fax (607) 762-8666
Email: RPKinney@nyseg.com

Alternate
Joseph Fleury – Director, Operations
Tel. (607) 762-4698
Fax (607) 762-4862
Email: jcfleury@nyseg.com

Rochester Gas and Electric Corporation
John Allen – Manager, NERC Compliance
Tel. (585) 771-4196
Fax (585) 771-4848
Email: John_Allen@rge.com

Nova Scotia Power Incorporated
Paul Casey - Director, Reliability and Control
Centre Operations
Tel. (902) 428-7721
Fax (902) 428-7799
Email: paul.casey@nspower.ca

Alternate
David Stanford – Compliance Manager
Tel. (902) 428-7768
Fax (902) 428-7715
Email : david.stanford@nspower.ca

Hydro One Networks Inc.
Paul Tremblay – Director, Network Operating
Division
Tel. (705) 792-3003
Fax (705) 792-3012
Email: Paul.tremblay@HydroOne.com

Alternate
John Sabiston - Transmission Plans Manager
West
Tel. (416) 345-5390
Fax
Email : john.sabiston@HydroOne.com

Sector 2 - Reliability Coordinators

New Brunswick System Operator
Alden Briggs – Senior Director, Power System Engineering
Tel. (506) 458-4479
Fax (506) 458-3920
Email: alden.briggs@nbso.ca

NPCC, Inc.

Sector 2 - Reliability Coordinators
(continued)

ISO-New England, Inc.
Donald L. Gates - Manager, Reliability and Operations Services
Tel. (413) 535-4350
Fax (413) 535-4050
Email: dgates@iso-ne.com

Alternate
Mike Henderson – Director, Regional Planning & Coordination
Tel. (413) 535-4166
Fax (413) 540-4203
Email: mhenderson@iso-ne.com

New York Independent System Operator
Henry Chao – Vice President of System Economic & Resource Planning
Tel. (518) 356-6111
Fax (518) 356-7524
Email: hchao@nyiso.com

Alternate
Dana Walters – Director, Reliability & Planning
Tel. (518) 356-8582
Fax (518) 356-7524
Email: dwalters@nyiso.com

Independent Electricity System Operator
Barbara Constantinescu - Director - Planning & Assessments
Tel. (905) 855-6406
Fax (905) 403-6932
Email : barbara.constantinescu@ieso.ca

Alternate
Len Kula – Manager System Operations
Tel. (905) 855-4115
Fax (905) 855-6319
Email : len.kula@ieso.ca

Hydro-Québec TransÉnergie
Pierre Paquet – Director, System Control
Tel. (514) 879-4655
Fax (514) 879-4689
Email: paquet.pierre@hydro.qc.ca

Sector 3 - Transmission Dependent Utilities, Distribution Companies and Load-Serving Entities

Hydro-Québec Distribution
Stéphane Dufresne – Manager Planning & Reliability
Tel. (514) 289-2733
Fax (514) 289-7355
Email : Dufresne.Stephane@hydro.qc.ca

Alternate
Luc Bernier – Senior Analyst, Supply Planning
Tel. (514) 289-2411 x 6902
Fax (514) 289-7355
Email: Bernier.Luc@hydro.qc.ca

NPCC, Inc.

Sector 3 - Transmission Dependent Utilities, Distribution Companies and Load-Serving Entities
(continued)

Long Island Power Authority
Curt Dahl – Director of System Planning

Tel. (516) 545-4908
Fax (516) 545-3662
Email: cdahl@service.lipower.org

Alternate
Steve Marron – Principal Engineer, System Planning
Tel. (516) 545-2644
Fax (516) 545-3662
Email: stephen.marron@us.ngrid.com

New York Power Authority
Marilyn Brown – Manager, Market Analysis & Tariff Administration
Tel. (914) 390 - 8115
Fax (914) 390 – 8156
Email: Marilyn.brown@nypa.gov

Alternate
Andrew Stewart
Tel. (914) 287-3201
Fax (914) 390-8156
Email: andrew.stewart@nypa.gov

Northeast Utilities
Dwayne Basler – Director Transmission Operations & Reliability Compliance
Tel. (860) 665-6196
Fax (860) 665-2322
Email: basledm@nu.com

Sector 4 - Generator Owners

Dominion Resources Services, Inc.
Michael Garton - Manager Electric Market Policy
Tel. (804) 818-2336
Fax
Email: Mike.Garton@dom.com

Alternate
Michael Gildea – Director NERC Compliance
Tel. (804) 819-2153
Fax
Email: Michael.gildea@dom.com

Dynegy, Inc.
Jim Watson – Manager Electric Systems

Tel. (217) 492-6603
Fax (217) 492-6633
Email: james.b.watson@dynegy.com

Alternate
Dean Ellis –Senior Manager Government and Regulatory Affairs
Tel. (518) 280-1482
Fax (713) 356-2910
Email: dean.ellis@dynegy.com

Sector 4 - Generator Owners
(continued)

Entergy Nuclear Northeast, Inc.
Thomas Czerniewski – Senior Staff Engineer
Tel. (914) 272-3368
Fax (914) 272-3537
Email: tczerni@entergy.com

NextEra Energy Resources
Benjamin Church – Director, Reliability & Compliance
Tel. (561) 304-5463
Fax (561) 304-5161
Email: benjamin_church@fpl.com

Alternate
David Applebaum – Director, Regulatory Affairs
Tel. (609) 771-0894
Fax (609) 771-0895
Email: david_applebaum@fpl.com

Long Island Power Authority
Yuri Fisman
Tel. (516) 545-4219
Fax (516) 545-3662
Email: yfishman@service.lipower.org

New York Power Authority
Edward Welz – Exe. Vice President & Chief Engineer Power Supply
Tel. (914) 681-6675
Fax (914) 681-6216
Email: edward.welz@nypa.gov

Alternate
Brad Van Auken – Vice President – Engineering Power Supply
Tel (914) 681-6218
Fax (914) 681-6534
Email: bradford.vanauken@nypa.gov

Ontario Power Generation, Inc.
David Ramklawan P.Eng – Sr. Regulatory Analyst
Tel. (416) 592-6089
Fax (416) 592-8519
Email: david.ramkalawan@opg.com

Northeast Utilities
William Smagula - Director – PSNH Generation
Tel. (603) 634-2851
Fax (603) 634-2703
Email: smaguwh@nu.com

Alternate
Drew O'Keefe – Supervisor - Engineering Services
Tel. (603) 634-2544
Fax (603) 634-3283
Email: okeefdj@nu.com

NPCC, Inc.

Sector 5 - Marketers, Brokers, and Aggregators

Constellation Energy Commodities Group, Inc.
Glen McCartney – Vice President
Tel. (410) 470-5145
Fax (410) 470-2499
Email: glen.mccartney@constellation.com

Hydro- Québec Energy Services (US) Inc.	Alternate
Louis Guilbault - Manager - Regulatory Affairs (New England)	Scott Leuthauser – Utility Consultant
Tel. (514) 289-2553	Tel. (315) 288-4201
Cell (514) 247-5386	Fax (315) 288-4201
Email: guilbault.louis.2@hydro.qc.ca	Email: sleuthau@twcny.rr.com

Hydro- Québec Energy Marketing, Inc.
Yannick Vennes - Manager, US Regulatory Affairs (NYISO)
Tel (514) 289-2093
Fax (514)289-6217
Email: Vennes.Yannick@hydro.qc.ca

Long Island Power Authority
Ben Chu – Director of Power & Fuel Operations
Tel. (516) 222-7700
Fax (516) 222-9137
Email: bchu@lipower.org

New York Power Authority	Alternate
William Nadeau – Sr. Vice President, Energy Resource Management & Strategic Planning	William Palazzo – Director, Market Issues Group
Tel. (914) 681-6801	Tel. (914) 681-6803
Fax (914) 681-6297	Fax (914) 681-4250
Email: william.nadeau@nypa.gov	Email: william.palazzo@nypa.gov

PPL EnergyPlus, LLC	Alternate
Bradley Weghorst – Market/Regulatory Policy Manager	Mark Heimbach – Generation Dispatch Manager
Tel. (610) 774-5285	Tel. (610) 774-4571
Fax (610) 774-6523	Fax (610) 774-4360
Email: bpweghorst@pplweb.com	Email: maheimbach@pplweb.com

NPCC, Inc.

Sector 5 - Marketers, Brokers, and Aggregators
(continued)

Utility Services LLC
Brian Evans-Mongeon – Principal
Tel. (802) 552-4022
Fax (866) 214-8632
Email: brian.evans-mongeon@utilitysvcs.com

Alternate
John Helme
Tel. (802) 552-4022
Fax (866) 214-8632
Email: john.helme@utilitysvcs.com

Sector 6 – State and Provincial Regulatory and/or Governmental Authorities

New York State Department of Public Service
TBA

Alternate
Edward Schrom, Jr. – System Planning
Tel. (518) 486-2890
Fax (518)473-2420
Email: edward_schrom@dps.state.ny.us

New York Power Authority
Bruce Metruck – Manager, Reliability Standards & Compliance
Tel. (315) 792-8213
Fax (315) 792-8332
Email: bruce.metruck@nypa.gov

Sector 7 – Sub-Regional Reliability Councils, other Regional Entities and Interested Entities

New York State Reliability Council, LLC
Roger Clayton - Electric Power Resources, LLC
Tel. (518) 588-6362
Email: roger.clayton@electricpowerresources.com

Alternate
George C. Loehr – Chairman, Executive Committee
Tel. (505) 792-0643
Fax (505) 792-0644
Email: gloehr@eLucem.com

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

Approval of
Public Information Committee
2012

Chairman: Steve Allen
Salient Point LLC

Members:

New England
Ellen Foley
ISO New England Inc.

New York
Michael Clendenin
Consolidated Edison Company of New York, Inc

John Cordi
New York Independent System Operator

PJM

Ray E. Dotter
PJM Interconnection

Maritimes
Michel Losier
NB Power Holding Corporation

Midwest ISO

(To Be Designated)

Quebec

(To Be Designated)

Ontario

Terry Young
Independent Electricity System Operator

ReliabilityFirst Corporation

Larry Bugh
ReliabilityFirst Corporation

NERC

Kimberly Mielcarek
North American Electric Reliability Corporation

Alternates: Vera B. Geba
Salient Point LLC

Gary N. Paslow
New York Independent System Operator

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

DESIGNATION OF
NORTHEAST POWER COORDINATING COUNCIL, INC. (NPCC)
OFFICERS
2012

****

Edward A. Schwerdt	President and CEO
Jennifer Budd Mattiello	Vice President and COO
William G. Longhi	Vice Chairman
Bruce B. Campbell	Vice Chairman
Andrianne S. Payson, Esq.	Secretary
Andrew J. Fawbush, Esq.	Assistant Secretary
Christopher Weir, CPA	Treasurer
Robert J. DeAngelo	Assistant Treasurer

20111115-3000 FERC PDF (Unofficial) 11/15/2011

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426
OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RR11-2-000

November 15, 2011

Schiff Hardin LLP
1666 K Street, N.W., Suite 300
Washington, D.C. 20036-4390

Attention: Owen E. MacBride
Attorney for North American Electric Reliability Corporation

Reference: Petition for Approval of Compliance Monitoring and Enforcement Agreement Between Northeast Power Coordinating Council, Inc. and Western Electricity Coordinating Council and Related Amendments to Delegation Agreements

Dear Mr. MacBride:

1. On May 25, 2011, the North American Electric Reliability Corporation (NERC) submitted a petition requesting approval of: (1) an agreement between Northeast Power Coordinating Council, Inc. (NPCC) and Western Electricity Coordinating Council (WECC) concerning compliance monitoring and enforcement of WECC registered functions; (2) an agreement between NERC and WECC regarding termination of the existing agreement concerning compliance monitoring and enforcement of WECC registered functions; and (3) related amendments to delegation agreements between NERC and NPCC, and NERC and WECC. NERC requests an effective date of January 1, 2012.

2. NERC states that the purpose of its petition is to provide for NPCC to assume responsibility for performing Regional Entity compliance monitoring and enforcement program functions with respect to those reliability functions for which WECC is the registered entity within the United States portion of the WECC region. Currently, NERC acts as the Compliance Enforcement Authority for WECC registered functions in the United States portion of the WECC region, pursuant to an agreement between NERC and WECC.

20111115-3000 FERC PDF (Unofficial) 11/15/2011

3. Notice of this filing was issued on May 25, 2011, with comments, protests or motions to intervene due on or before June 15, 2011. No protests or adverse comments were filed.

4. NERC's uncontested filing is accepted pursuant to the authority delegated to the Director, Office of Electric Reliability, under 18 C.F.R. § 375.303, effective January 1, 2012.

5. This action shall not be construed as accepting any other contingency plan pursuant to 18 C.F.R. § 375.303(a)(1)(i) or any other data or report pursuant to C.F.R. § 375.303(b)(3)(iv). This action shall not be construed as approving any other application including Electric Reliability Organization or Regional Entity Rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such acceptance or approval shall not be deemed as recognition of any claimed right or obligation associated therewith; and such acceptance or approval is without prejudice to any findings or orders which have been or which may hereafter be made by the Commission in any proceeding now or pending or hereafter instituted by or against NERC.

6. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Joseph H. McClelland, Director
Office of Electric Reliability

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Media Release

NERC Completes First Grid Security Exercise

November 17, 2011

WASHINGTON, DC – More than 75 industry and government partners participated in the North American Electric Reliability Corporation's (NERC) first cybersecurity readiness exercise, GridEx 2011, this week.

Ending today, the two-day exercise is part of NERC's ongoing security readiness program to assess NERC and the industry's crisis response plans and validate current readiness in response to a cyber incident. GridEx, which NERC plans to sponsor bi-annually, also allowed enhanced collaboration between NERC, the industry and government stakeholders.

"GridEx 2011 is an opportunity for NERC, industry stakeholders and government partners to work together and identify gaps in the overall security posture of the grid," said Mark Weatherford, vice president and chief security officer at NERC. "Most importantly, it will provide data to help the electricity sector focus resources to better address cybersecurity issues."

GridEx, modeled after the Department of Homeland Security's CyberStorm exercise series, allowed participants to respond to scenario events as they would in the case of a real-time incident. This will enable participants and leadership to assess, test and validate existing crisis response plans; and to adjust plans as needed in an exercise setting.

Participants included NERC and Regional Entities, electric sector utilities, Department of Energy, Department of Homeland Security and Department of Defense, as well those from the Federal Energy Regulatory Commission and Canadian agencies. For more information on NERC's cybersecurity program, click here or visit NERC's website at www.nerc.com.









CONTACT:
Kimberly Mielcarek
202-383-2622

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards Development Plan

2012-2014

Approved by Board of Trustees
November 3, 2011

RELIABILITY | ACCOUNTABILITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Chapter 1 – Executive Summary 1

Chapter 2 – A Joint Letter from the Chair of the Standards Committee and NERC's Vice-President of Standards and Training 2

Chapter 3 - General 5

Status Updates 6

2011 Reorganization and Hiring 6

Completed Standards Development Projects 6

Progress on Version Zero Standards 6

Interpretations of Reliability Standards 7

Progress on Regulatory Directives 7

Regional Standards Development 8

Rapid Development and Rapid Revision Projects 8

Challenges facing Standards 9

Five-Year Review Obligation 9

Product Quality 9

Standards Program Throughput 9

Conclusion 10

Chapter 4 – Project Development Overview 11

Project Prioritization and Plan Development 11

Project Implementation 12

Chapter 5 – Project Work Plan Summary 14

Projects for 2012-2014 14

Projects for 2015 and Beyond 17
Appendix 1 - Prioritization 18
Appendix 2 – Work Plan 38
Appendix 3 – Regional Work Plan 38
Appendix 4 – Project Summaries 40
Project 2006-06 Reliability Coordination 41
Project 2006.06.2 Phase 2 of Reliability Coordination: IRO-003 42
Project 2007-02 Operating Personnel Communication Protocols 43
Project 2007-03 Real-time Transmission Operations 44
Project 2007-06 System Protection Coordination 45
Project 2007-07 Vegetation Management 46
Project 2007-09 Generator Verification 47
Project 2007-11 Disturbance Monitoring 48
Project 2007-12 Frequency Response 49
Project 2007-17 Protection System Maintenance and Testing 50
Project 2008-01 Voltage and Reactive Planning and Control 51
Project 2008-02 Undervoltage Load Shedding 52
Project 2008-06 Cyber Security – Order 706 53
Project 2008-12 Coordinate Interchange Standards 54
Project 2009-01 Disturbance and Sabotage Reporting 55
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities 56
Project 2009-03 Emergency Operations 57
Project 2009-04 Phasor Measurements 58
Project 2009-05 Resource Adequacy Assessments 59
Project 2009-07 Reliability of Protection Systems 60

Project 2010-01 Support Personnel Training 61

Project 2010-02 Connecting New Facilities to the Grid..... 62

Project 2010-03 Modeling Data..... 63

Project 2010-04 Demand Data 64

Project 2010-05.1 Phase 1 of Protection Systems: Misoperations 65

Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS..... 66

Project 2010-07 Generator Requirements at the Transmission Interface 67

Project 2010-08 Functional Glossary Model Revisions 68

Project 2010-13.2 Phase 2 of Relay Loadability: Generation 69

Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings 70

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves 71

Project 2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent 72

Project 2010-16 Definition of System Operator 73

Project 2010-17 Definition of Bulk Electric System 74

Project 2012-01 Equipment Monitoring and Diagnostic Devices..... 75

Project 2012-02 Physical Protection..... 76

Project 2012-03 PRC-004 VSLs..... 77

Project 2012-04 Protection System Commissioning Testing..... 78

Project 2012-05 ATC Revisions - Order 729..... 79

Project 2012-06 Generator Capabilities 80

Project 2012-07 Obsolescence Review..... 81

Project 2012-08 Glossary Updates 82

Project 2012-09 IRO Review 83

Project 2012-11 FAC Review..... 84

Project 2012-12 PER Review..... 85

Project 2012-13 NUC Review 86

Project 2012-14 Risk Analysis 87

Project 2012-15 Flow Limited Paths 88

PRC-002-FRCC-1 — FRCC Regional Disturbance Monitoring and Reporting Requirements 89

PRC-003-FRCC-1 — FRCC Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems 90

PRC-006-FRCC-1 — FRCC Automatic Underfrequency Load Shedding Program..... 91

PRC-024-FRCC-1 — FRCC Regional Generator Performance During Frequency and Voltage Excursions 92

PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding Program 93

PRC-012-NPCC-1 — Special Protection Systems 94

MOD-024-RFC-1 — Verification and Data Reporting of Generator Gross and Net Real Power Capability 95

MOD-025-RFC-1 — Verification and Data Reporting of Gen Gross and Net Reactive Power Capability 96

PRC-002-RFC-1 — Disturbance Monitoring and Reporting Requirements 97

PRC-006-RFC-1 — Automatic Under Frequency Load Shedding Requirements 98

PRC-012-RFC-1 — Special Protection System Requirements 99

PRC-006-SERC-01 — Automatic Underfrequency Load Shedding Requirements 100

PRC-006-SPP-1 — Under Frequency Load Shedding 101

IRO-006-TRE-1 — IROL and SOL Mitigation in the ERCOT Interconnection 102

BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region..... 103

BAL-002-WECC-1 — Contingency Reserves..... 104

BAL-004-WECC-1 — Automatic Time Error Correction 105

VAR-001-WECC-1 — Voltage and Reactive Control..... 106

Chapter 1 – Executive Summary

This document provides an update on the status of Standards Development work at NERC, as well as a forecast of work being planned for 2012-2014. The document has several sections:

- Chapter 1 contains this Executive Summary
- Chapter 2 contains introductory remarks from the Chair of the Standards Committee and NERC's Vice-President and Director of Standards
- Chapter 3 provides a general update on Standards Activities in 2011
- Chapter 4 provides a summary of the development of this document and the implementation of projects in general
- Chapter 5 provides a summary of the Work Plan
- Appendix 1 shows the prioritization scores used in the development of the Work Plan
- Appendix 2 shows the Work Plan in Gantt chart form
- Appendix 3 shows the Regional Work Plan in Gantt chart form
- Appendix 4 provides brief summaries of all the projects proposed within the Work Plan

Chapter 2 – A Joint Letter from the Chair of the Standards Committee and NERC's Vice-President of Standards and Training

To: NERC's Board of Trustees, Stakeholders, Regulatory Authorities, and other interested parties

NERC is committed to the development of clear, technically excellent standards for the reliable planning and operation of the North American bulk power system. NERC's industry-based standard development process strives to leverage the knowledge and experience of subject-matter experts to develop stakeholder consensus in support of standards that achieve reliability objectives and are responsive to regulatory directives, balanced against the burdens and costs of compliance imposed upon the more than 1,900 entities that are now subject to these standards. No single standard can ensure this outcome. Rather, NERC strives to develop and enhance a portfolio of performance, risk-mitigation, and competency-based reliability standards that achieve a consistent defense in depth against credible events that may lead to cascading, uncontrolled separation, or instability and ensure prompt system restoration when extreme events occur.

Achieving this balance is intrinsically difficult. Just as the management of the reliability "bar" through enforceable standards is an ongoing and evolving process, the process for developing standards needs to evolve as well, in response to the learning that has occurred in the period since passage of the Energy Policy Act of 2005 and the initial enforcement of NERC standards in June 2007. We would like to use this message to highlight current achievements in the standards arena and our plans for 2012-2014, as well as certain emerging factors and concerns.

NERC's Reliability Standards Development Plan delivered the following results in 2011:

- As of November 1, 2011, 20 new or revised standards have been approved by the Board of Trustees, and are either filed or in the process of being filed with the FERC.
- Results Based Standard development principles were used for all new standards projects.
- The Standards Committee worked with NERC staff to prioritize standards development resources on twelve high priority projects. There has been no specific redirection of this effort relative to the selected priorities by regulatory authorities.
- Stakeholder-driven Quality Review has been integrated into the standards development process to assure the best quality standards from a compliance and implementation perspective.
- NERC undertook a first effort to develop a standard on a Rapid Development basis utilizing the new Standard Processes Manual.

- To balance the resources committed to the development of new standards versus the interpretation of existing standards, the Standards Committee has limited the number of interpretations under active development to three projects at any one time, while pursuing new procedural options such as "rapid revision" to correct deficiencies in the underlying standard.

The 2012-14 Reliability Standards Development Plan described in this report builds on recent experience by proposing an achievable yet ambitious plan of standards development. The 2012-14 Plan provides for:

- Continuation of ongoing standards projects with sufficient resources to ensure timely completion.
- Project priorities were established using a more comprehensive model with scores and explanatory inputs from the Standards Committee, NERC staff and industry stakeholders.
- Projects have been ranked for development priority along three tracks, based on consideration of Reliability Benefits, Time Sensitivity, and Practicality.
- As ongoing projects are completed, we are scheduling follow-on projects based on the availability of subject-matter experts and the completion of technical input, research, and industry outreach conducted by NERC's standing committees and subcommittees.
- Finally, the 2012-14 Plan incorporates a more comprehensive integration of the regional standards effort into this process. For the first time a complete project management process is being applied to regional standards development.

This Plan is intended to be a forecast of the standards work expected to be developed in the coming years. However, a wide variety of electric system events and emerging risks to bulk power system reliability may necessitate deviations from this plan. In order to respond to such threats and initiate development of new or revised standards, the actual deployment of resources to staff this plan may shift. Additionally, the estimated times listed for project completion may change as more is learned about a given project.

NERC currently is investigating the following "emerging issues," each of which may result in the identification of additional standards development work:

- Cold weather preparedness and winterization
- Geomagnetic disturbances
- Right-of-way clearances and maintenance
- System design and planning
- High Impact/Low Frequency events and disaster preparedness

Not every issue is addressable or best addressed through development of a new industry standard; the issues outlined above illustrate that truism. But where a standards related response is indicated, we will be ready to reprioritize and adjust.

The Standards Committee and NERC staff also recognize that major standards process efficiencies are still necessary if we are to make efficient use of NERC and industry resources, while meeting external expectations for the timely development and approval of technically excellent reliability standards. In 2012, we need to ask ourselves once again, "is there a better way to develop reliability standards?"

We achieve the past results and plan for the future results only with your support, and greatly appreciate that the industry has accepted the evolving prioritization process. Our efforts to effectively manage and balance the many conflicting demands placed upon both the industry and NERC staff resources has provided this next plan, which we hope you will endorse.

Each of us, day in and day out, is driven to do the "right" thing, and your ERO's reputation will be enhanced through your active support for completion of NERC's 2012-14 Reliability Standards Development Plan.

Sincerely,



Allen Mosher
Senior Director of Policy Analysis and Reliability, American Public Power Association
Chair, NERC Standards Committee



Herb Schrayshuen
Vice President of Standards and Training, NERC

Chapter 3 - General

This is the Reliability Standards Development Plan (the "Plan") for years 2012-2014. The Plan provides several items of interest to its readers:

- Information regarding the state of Standards at NERC, changes in Standards, and challenges facing Standards in the years to come;
- Status updates regarding standards and related projects currently in development;
- A forecast of Standards Development work scheduled for the next three years; and
- An overview of the process used to prioritize work and assign resources to Standards development projects.

NERC Standards staff endeavors to maintain a complete, updated set of Standards information on the NERC website, which can be found at www.nerc.com.

The Standards Program continues to manage its ongoing load of work in order to move toward the target work load levels initially identified in early 2011. Progress is being made in this area; however, some projects expected to be completed in 2011 are still in active development. This is largely due to unforeseen complications regarding achieving consensus and managing overall product quality.

This Plan is intended to be a forecast of the standards work expected to be developed in the coming years. However, other priorities may necessitate deviations from this plan. As new technologies are discovered or new threats to reliability identified, the actual deployment of resources to staff this plan may shift. Similarly, the estimated times listed for project completion may change as more is learned about a given project.

NERC is currently investigating the following "emerging issues," which may result in the identification of additional standards development work:

- Cold weather preparedness and winterization
- Geomagnetic disturbances
- Right-of-way clearances and maintenance
- System design and planning
- High Impact/Low Frequency events and disaster preparedness

Status Updates

2011 Reorganization and Hiring

In early 2011, NERC performed a minor reorganization of the Standards staff in order to ensure appropriate focus on key areas. A new position, Director of Regulatory Initiatives, was established to ensure overall coordination between NERC and its various regulators. NERC also established a Manager of Standards Information, with the primary focus of ensuring that information posted on the NERC website accurately reflects the current body of Standards and associated compliance information. Additional staff was hired into the Standards Process, Standards Development, and Regional Standards teams to better support the volume of work ongoing within the Standards Program.

Completed Standards Development Projects

In 2011, NERC completed development of the following projects.

- 2006-02 Assess Transmission and Future Needs (BOT approved, awaiting filing)
- 2007-04 Certifying System Operators (filed with regulators)
- 2008-06 Cyber Security Order 706 Version 4 (filed with regulators)
- 2009-06 Facility Ratings (filed with regulators)
- 2010-10 FAC 729 (filed with regulators)
- 2010-11 TPL Table 1 Footnote B (filed with regulators)
- 2010-13 Relay Loadability Order Phase 1 (filed with regulators)

Progress on Version Zero Standards

The set of Version 0 standards included 110 standards. Of the 110 standards, NERC withdrew three, and the Federal Energy Regulatory Commission (FERC) ruled on the remaining 107 as follows:

- 27 were approved without any directives to modify the associated standard
- 56 were approved with directives to modify the associated standard
- 24 were not approved, pending provision of additional information

Of the 56 that were approved with directives, progress in revising those standards includes:

- 7 have been approved by FERC
- 9 have been submitted and are pending FERC approval
- 18 are associated with projects under active development

- 22 are associated with projects that are either inactive or not started

Of the 24 that were not approved pending submittal of additional information, progress in revising those standards includes:

- 8 have been approved by FERC
- 4 have been submitted and are pending FERC approval
- 2 are associated with projects under active development
- 10 are associated with projects that are either inactive or not started

As of September 1, 2011, there are 103 continent-wide Reliability Standards with 1220 requirements that are mandatory and enforceable in the United States.[1]

Interpretations of Reliability Standards

Entities required to comply with a reliability standard have the right to request a formal interpretation of a requirement in a standard. Interpretation projects generally are narrower in scope than other standards projects, but like standards, interpretations are drafted by a drafting team and posted for industry review and ballot. From 2006 to 2011, NERC processed 43 interpretation requests. In addition, NERC received a number of requests for interpretation that were absorbed into standards development projects because drafting teams could not prepare the interpretations without expanding the requirements of the approved standard.

Progress on Regulatory Directives

Since NERC became the Electric Reliability organization (ERO), FERC has issued 44 Orders containing approximately 655 directives related to NERC Reliability Standards. Of the approximately 655 directives issued since 2007, NERC has completed projects associated with approximately 44% of these directives and continues to make substantial progress in addressing the remaining directives focusing first on those that have the greatest impact on reliability.

A significant number of the directives ordered by FERC for implementation by NERC (as the FERC-approved ERO) specify that NERC submit or modify a Reliability Standard that addresses a specific matter, as permitted under Section 215(d)(5) of the Federal Power Act. Other directives order NERC to make changes in its procedural rules. Still other directives order NERC to consider the views of various commenters when NERC next revises a particular Reliability Standard.

[1] The data included in this paragraph does not include Regional Reliability Standards.

NERC processes these various types of directives consistent with its Rules of Procedure (including Appendices 3A- Standard Processes Manual and 3C Procedure for Coordinating Reliability Standards). Specifically, when a regulatory order or rule is issued, that order is reviewed and any directives within the order related to standards development are added to the NERC Standards Issues Database and categorized. NERC then seeks to associate each directive with a specific standard. Projects and the associated Standards, along with the associated regulatory directives, are then prioritized for revision using the prioritization process described elsewhere in this document.

In 2011, NERC developed and filed the first NERC Standards Report, Status and Timetable for Addressing Regulatory Directives. This report is to be filed annually with FERC on or before March 31 of each year in accordance with Section 321.6 of the NERC Rules of Procedure ("Rule 321") that was approved by the FERC on March 17, 2011. The progress against the directives issued is outlined in the aforementioned report.

Regional Standards Development

Regional standards work within NERC and the Regions has seen a great deal of development and implementation of new initiatives since the beginning of 2011. First, the Regional Reliability Standards Working Group (RRSWG) transitioned into the Regional Standards Group (RSG). Comprised of the NERC Vice President of Standards and Training and the Standards Managers from each of the eight Regional Entities, the RSG reports to the ERO Executive Management Group (EMG). Its purpose is to provide process and policy recommendations in the execution of the Regional Entity delegation agreements and the NERC Rules of Procedure. An overarching objective is to coordinate the development of Regional and continent-wide standards to support and continually enhance reliability across North America for the benefit of all bulk electric system users, owners and operators.

In support of this purpose and this objective, a primary initiative of the RSG is to create and sustain viable standards development coordination processes to obtain consistency and uniformity, where appropriate, across the ERO enterprise – NERC and the Regional Entities – while ensuring efficient and effective use of resources in executing the statutory responsibilities of the ERO as the reliability standards development authority. To that end, the RSG developed a combined list of all regional standards and variances in the development process in order to prioritize these projects continent-wide. This will allow NERC to coordinate the necessary resources through the development and ultimate filing of these standards and variances with applicable regulatory authorities. Project information for each of those regional standards and variances in the development process is provided in this Plan, along with a high-level overview of the project timeline.

Rapid Development and Rapid Revision Projects

NERC's Standards Committee (SC) tentatively has identified two ways to accelerate project development while staying within the boundaries established in the Standard Processes Manual. Both approaches are consistent with the original vision of standards development when the ERO was being developed.

The first, called "Rapid Development," utilizes a small team of professionals to draft a standard over a short, but intensive period of time. The standard is then submitted with its associated SAR and the project moves directly into the first formal comment phase. Under this model, it may be possible to develop and ballot a standard within a period less than a year. The SC is evaluating the approach as part of Project 2010-05.1 Phase 1 of Protection Systems: Misoperations. Initial results have provided useful lessons learned, including the need to carefully select members of the small team to ensure not just subject matter expertise, but balance of interests as well.

The second approach, called "Rapid Revision," takes a similar approach, but is focused on dealing with concerns identified during the Interpretation process. If an interpretation drafting team identifies simple modifications to a standard that can address an interpretation request more effectively than an interpretation can alone, the team may propose to the requester that the team instead make such changes and submit them with an associated SAR. If agreed to by the requester, and following SC review, the changes may move directly to comment and ballot. This approach is being tested with project 2011-INT-01 Interpretation of MOD-028-1 R3.1 for Florida Power and Light.

Challenges facing Standards

Five-Year Review Obligation

As part of its Rules of Procedure, NERC has committed to review each of its standards for modification once every five years. 2012 marks the fifth year since NERC's first set of standards became mandatory and enforceable in the United States; many of those standards are now due for that five-year review. While not giving the appearance of being onerous, this obligation has proved challenging to meet. The work load of the ERO remains high, and maintaining focus on those projects that are most beneficial to reliability has resulted in a delay of the work required for these five-year reviews (except when already associated with a project of significant reliability value). Using current assumptions, the five-year review obligation will not be met for a number of standards. NERC and the SC are working together with the NERC Board of Trustees to evaluate options for addressing this issue.

Product Quality

As NERC's and the industry's experience with standards has evolved, it has become increasingly clear that minor problems with the quality of standards can have significant repercussions when it comes to clarity and compliance. NERC has undertaken efforts to improve the quality of its work products, and will continue to do so in 2012. Steps being taken include creating technical writer positions, enhanced training for staff, and developing additional internal quality assurance processes.

Standards Program Throughput

One continuing challenge is the ability to not only produce quality products, but to do so consistently and efficiently. While in some cases limited by necessity due to the scarcity of industry resources available in the workforce, the Standards Program continues to look for ways to improve the efficiency of its processes and its ability to demonstrate tangible progress

in standards development on a regular basis. In 2012, Standards staff will be implementing enhanced document management capabilities, as well as portfolio-level project controls to ensure optimal use of resources and overall consistency of throughput. This more global "portfolio view" was used to in part to develop this Plan, but additional improvements are expected in 2012 as well. As such, it should be noted that this, in addition to the normal variables associated with consensus-based product development, may lead to changes in the schedules used to develop the forecasts within this document

Conclusion

The Standards Program continues to make changes to improve its overall effectiveness, and looks forward to additional improvements in 2012. The SC's work on this Plan has appropriately focused the industry on standards development to ensure the best progress in improving reliability, addressing concerns in a timely manner, and assisting with implementation complexity. Additionally, the plan was developed with the use of a subjective review of the implications of cost. NERC believes this approach correctly balances the needs of the industry with the public interest, and will continue to work with the industry to ensure the continued protection of reliability in North America.

Chapter 4 – Project Development Overview

Project Prioritization and Plan Development

This year, NERC continued use of the Prioritization Tool (the Tool) developed by the Standards Committee (SC) in late 2010 and early 2011 to help determine how best to assign resources and perform work. Following the finalization of the 2011-2013 Plan, the Standards Committee's Process Subcommittee (SCPS) began to work on improving the Tool for use in the development of the 2012-2014 Plan.

Similar to last year, the Tool utilizes a simple scoring mechanism to identify key considerations for use in determining project priority. Revisions were made to the tool in response to comments received during the development of the 2011-2013 Plan. Changes included the elimination and consolidation of scores that seemed to overlap or be redundant, removal of the "Project Percent Complete" evaluations (as there is currently no intention of moving projects into Informal Development, as was considered during the development of the 2011-2013 Plan), the addition of a score to account for projects related to the NERC President's Top Priority Issues for Bulk Power System Reliability, and trial testing of a new metric that accounts for "cost considerations." In addition, the Tool was modified to allow a more sophisticated analysis of each of the key drivers in project prioritization. This allowed the SC to consider each of those factors separately, as well as in aggregate, to determine how best to allocate resources.

During the month of July 2011, NERC solicited the industry at-large for additional projects for consideration in the 2012-2014 Plan. NERC received nine submissions, resulting in the creation of six new projects. NERC created one project to account for the remaining Order 729 directives yet to be resolved, and one project to account for issues with the MOD-029-01 standard that will need to be addressed at some point in the future. NERC created four additional projects to account for projects to modify standards based on NERC's five-year review obligation, as identified in its Rules of Procedure.

In August, the SC began reviewing each of these projects, assigning them various scores based on input from constituents within their respective segments. NERC staff assembled the results in September, and an initial Prioritization and Work Plan was approved for posting at the September meeting of the SC. This Work Plan assumed an overall throughput capacity of thirteen projects in development concurrently, and divided that capability into three areas:

- Reliability Projects – those projects expected to be the most beneficial to Reliability. Capacity for eight concurrent projects was assigned to this area.
- Time-Sensitive Projects – those projects with time sensitivity, such as those responsive to FERC orders with specified deadlines, as well as those projects needed to meet the ERO's five-year review obligation. Capacity for three concurrent projects was assigned to this area.

- Practicality Projects – those projects that improve the overall effectiveness of NERC's Reliability Standards, including addressing failed interpretations, improving the clarity of often violated standards, and other such general improvements. Capacity for two concurrent projects was assigned to this area.

The Work Plan identified each project and the amount of work associated with it, then allocated projects in their respective areas in order or priority as resources came available. Some projects were identified that needed additional research and were scheduled for initiation with sufficient time to allow such work to be completed. Additionally, some projects require specific expertise. To the extent such needs were identified, that expertise was managed to ensure the volume of work did not exceed the resource capacity. For example, projects related to protection systems generally were not started until another project related to protection systems was completed.

This Work Plan, along with the prioritization itself and this document in draft form, were posted for industry comment in September. Comments were received and considered at the October 2011 SCPS meeting; the final prioritization and Plan was approved by the SC at its October meeting. The Plan was presented to NERC' Board of Trustees and was approved at the Board's November meeting.

Project Implementation

Standards development projects at NERC proceed through a specific set of steps, identified in NERC's Standard Processes Manual. In general, the process can be summarized as follows:

- Initiation – projects are identified, and simple problem statements are developed. These problem statements are used to assist in the overall project prioritization effort described above.
- Planning – projects are further developed to determine their scope and merits. The drafting of a formal Standards Authorization Request (SAR) occurs in this step, as well as the development of communication plans if deemed to be necessary. In some cases, this step may occur concurrently with the initial steps of Execution and Control.
- Execution and Control – once the SC has approved a project for moving into this phase, standards or other work products are produced and the project begins moving forward in earnest. A detailed project schedule is developed, and standards are drafted, posted for comment, and balloted, culminating in review by NERC's Board of Trustees for adoption.
- Regulatory Submission - Following adoption by NERC's Board of Trustees, the standards are submitted to regulatory authorities.

- Closing – Following action by NERC's Board of Trustees, the project is reviewed and analyzed for "lessons learned." Public information is updated as necessary, and any necessary supplemental regulatory filings are made.

For more information on the specific details of each step in the implementation of projects to develop NERC Reliability Standards, readers are directed to various resources posted at the NERC Standards Resources page:

http://www.nerc.com/commondocs.php?cd=2

Chapter 5 – Project Work Plan Summary

This chapter summarizes the Reliability Standards Development Plan (the "Plan") for years 2012-2014. The following is based on the Standards Committee's Prioritization of Projects (included as Appendix 1) and the associated staff-developed Work Plan (included as Appendix 2). The Regional Work Plan is included as Appendix 3. A detailed summary of projects, including regional projects, is included as Appendix 4.

Projects for 2012-2014

NERC intends to continue development of the following projects in 2012. These are Active Projects, and are expected to continue until completion. Although there are other projects that ranked higher this year than some of these projects, the Standards Committee believes that the industry has committed to completing these projects, and given that the workload is reaching a manageable size, moving any of these projects into informal development would be counterproductive.

The projects below have been color coded, to indicate their focus area (Reliability, Time Sensitivity, or Practicality). While most projects impact all three of these areas in some way, this is intended to illustrate the primary consideration driving each project's development priority.

Existing Active Projects:

- 2006-06 Reliability Coordination.
- 2007-02 Operating Personnel Communication Protocols.
- 2007-03 Real-time Transmission Operations.
- 2007-06 Protection System Coordination.
- 2007-07 Vegetation Management. This project is expected to be completed in early 2012, but at the time of this document's finalization, it has not yet been formally completed.
- 2007-09 Generator Verification.
- 2007-12 Frequency Response.
- 2007-17 Protection System Maintenance and Testing.
- 2008-06 Cyber Security – Order 706.
- 2009-01 Disturbance and Sabotage Reporting.
- 2010-05.1 Phase 1 of Protection Systems: Misoperations.
- 2010-07 Generator Requirements at the Transmission Interface.
- 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves.
- 2010-17 Definition of Bulk Electric System.

NERC intends to initiate development of the following additional projects in 2012. These projects have been assigned based on priority, but constrained by the need to have a limited

number of projects under active development at any given time. Project 2010-05.2 is not schedule to start until later in 2012 due to the need for subject matter expertise in misoperations, which is already committed to Phase 1 of the project. 2012-04 is not starting until later in 2012 due to the need for subject matter expertise in protection system testing, which is already committed to Project 2007-17.

While this Plan is a reasonable approach to Standards development, it cannot account for unforeseen events. The Plan is subject to modification in response to factors such as delays in the completion of current projects, the need to complete background research prior to initiation of standards development work, unforeseen regulatory directives, and factors such as new or emerging reliability risks to the Bulk Electric System. Changes to the Plan during its execution are not only possible, but likely, and should be expected.

Additional Projects in 2012:

- 2008-02 Undervoltage Load Shedding.
- 2009-02 Real-time Monitoring and Analysis Capabilities. This project is currently in informal development.
- 2009-03 Emergency Operations. This project is currently in informal development.
- 2010-01 Support Personnel Training. This project requires research prior to initiation, which is expected to be completed in the earlier part of 2012.
- 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. This project is expected to be started upon the completion of the first phase of the project, 2010-05.1 Phase 1 of Protection Systems: Misoperations. This project requires research prior to initiation, which is expected to be completed in the earlier part of 2012.
- 2010-13.2 Phase 2 of Relay Loadability: Generation. This project is currently in informal development. This project has been identified as having a higher priority, as it has a FERC deadline. While this was accounted for in the Prioritization, the SC agreed that this should take precedence over the 5-year review projects considered in the Prioritization.
- 2012-04 Protection System Commissioning Testing. This project is expected to be started upon the completion of 2007-17 Protection System Maintenance and Testing. This project requires research prior to initiation, which is expected to be completed in the earlier part of 2012.

NERC intends to initiate development of the following projects in 2013. As noted above, these projects generally have been assigned based on priority and constrained by the need to have a limited number of projects under active development at any given time. 2012-06 is not starting until 2013 due to the need for subject matter expertise in reserves and in generator characteristics, which are already committed to projects 2010-14.1 and 2007-09, respectively. 2009-07 is not starting until 2013 due to the need for subject matter expertise in protection systems, which is already committed to project 2007-06.

Additional Projects in 2013:

- 2007-11 Disturbance Monitoring. This project is currently in informal development.
- 2008-01 Voltage and Reactive Planning and Control. This project is currently in informal development.
- 2008-12 Coordinate Interchange Standards. This project is currently in informal development.
- 2009-07 Reliability of Protection Systems. Based on the limited number of experts in this subject matter area, and the need for research prior to beginning work, this project is not expected to start until after the completion of 2007-06 Protection System Coordination.
- 2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent. This project is currently in informal development.
- 2012-01 Equipment Monitoring and Diagnostic Devices. This project requires research prior to initiation, which is expected to be completed in the latter part of 2012.
- 2012-06 Generator Capabilities. Based on the limited number of experts in this subject matter area, and the need for research prior to beginning work, this project is not expected to start until completion of both 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves and 2007-09 Generator Verification.

NERC intends to initiate development of the following projects in 2014. These projects have been identified as having a lower priority, although some are associated with the 5-year review obligation. In general, these projects are not projected to be initiated until 2014 due to the need to limit the number of projects active at any given time. 2010-13.3 is not projected to start until 2014 due to the need for subject matter expertise in relay loadability, which is already committed to Phase 2 of the project.

Additional Projects in 2014:

- 2009-04 Phasor Measurements. This project requires research prior to initiation, which is expected to be completed in 2013.
- 2009-05 Resource Adequacy Assessments.
- 2010-03 Modeling Data. This project requires research prior to initiation, which is expected to be completed in the latter part of 2013.
- 2010-04 Demand Data. This project requires research prior to initiation, which is expected to be completed in 2014.
- 2010-08 Functional Glossary Model Revisions.

- 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings. Based on the limited number of experts in this subject matter area, and the need for research prior to beginning work, this project is expected to not start until completion of the previous phase of this project, 2010-13.2 Phase 2 of Relay Loadability: Generation.
- 2010-16 Definition of System Operator.
- 2012-05 ATC Revisions - Order 729.

Projects for 2015 and Beyond

NERC intends to develop the following projects in 2015 or later, which is beyond the scope of this Plan. These projects have been identified as having a lower priority. There also is some question as to whether or not they will provide sufficient value to be cost justified at this time. They have been included for completeness and to ensure that they are recognized as necessary projects.

It should be noted that several of these projects are related to NERC's ongoing obligation to review its standard every five years, as required in the Rules of Procedure. This is discussed in more detail in the General chapter.

- 2010-02 Connecting New Facilities to the Grid
- 2012-02 Physical Protection
- 2012-03 PRC-004 VSLs
- 2012-07 Obsolescence Review
- 2012-08 Glossary Updates
- 2012-09 IRO Review
- 2012-11 FAC Review
- 2012-12 PER Review
- 2012-13 NUC Review
- 2012-14 Risk Analysis

The following two projects were identified as potential projects for consideration, but not included in the prioritization. If necessary, they will be evaluated mid-year on an ad-hoc basis; otherwise, they will be considered in the prioritization process for the 2013-2015 Reliability Standards Development Plan.

- 2006-06.2 Phase 2 of Reliability Coordination
- 2012-15 Flow Limited Paths

Appendix 1 - Prioritization

The following pages show the project rankings in each of the three primary categories: Reliability, Time Sensitivity and Practicality. The assignment of scores was based on the mean of individual scores provide by members of the Standards Committee. Scores highlighted in red indicate areas where the members of the SC were divided regarding how to assign a particular score.

Following the identification of potential projects, this prioritization is the next step in the creation of the Reliability Standards Development Plan, and provides a starting point for further discussion. The prioritization is used to create the Work Plan that follows as Appendix 2.

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization

RELIABILITY SORT

Project Number and Name	Short Description	(E) **Addresses an ERO Strategic Priority** (to be completed by NERC Staff) 50 = Yes 0 = No	(F) **Addresses a reliability risk not covered by an existing standard** 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	(G) **Improves one or more existing standards:** 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	(H) **Cost of Implementation** The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(I) **Cost of Administration** The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(J) **Time Sensitivity** (to be competed by NERC Staff) Number of months until due date, if any	(K) **Addresses compliance issues from NERC Staff or Stakeholders** 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	(L) **Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is** 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	(M) **Other Practicality Concern** (Explanation for the rating must be indicated in the column to the right) (0 to 50)	(N) **Explanation**	**Reliability Score (0 - 250)**	**Cost Consideration Score (0 - 100)**	**Time Sensitivity Score (0 - 100)**	**Practicality Score (0 - 150)**	**Reliability Ranking**	**Cost Consideration Ranking**	**Time Sensitivity Ranking**	**Practicality Ranking**
Project 2009-07 Reliability of Protection Systems	20 - Requires facility owners to have protection system equipment installed such that, if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards. Related to System Protection Initiative. New standard(s).	50	83.3	88.3	66.7	41.7	0	12.5	25			221.6	66	0	37.5	1	3	33	17
Project 2008-06 Cyber Security - Order 706 (ACTIVE)	13 - The project requires modifications to CIP-002 thru CIP-009 to bring the standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706.	50	70.8	100	87.5	75	48	45.8	45.8			220.8	52	22	91.6	2	17	29	6
Project 2007-17 Protection System Maintenance & Testing (ACTIVE)	10 - Intended to consolidate several standards into a single maintenance and testing standard: PRC-005 (Transmission and Generation Protection System Maintenance and Testing), PRC-008-0 (Underfrequency Load Shedding Equipment Maintenance Programs), PRC-011-0 (UVLS System Maintenance and Testing), and PRC-017-0 (Special Protection System Maintenance and Testing). Standards PRC-008-0, PRC-011-0, and PRC-017-0 would then be withdrawn. Related to System Protection Initiative.	50	50	100	60	50	5	45.8	25			200	60	94	70.8	3	7	7	9
Project 2007-06 System Protection Coordination (ACTIVE)	5 - Requires upgrading and expanding the existing requirements from PRC-001 to identify criteria for determining where to install protection system devices and for requiring the installation of those devices to protect the reliability of the bulk electric system. PRC-027. Related to System Protection Initiative.	50	62.5	83.3	55	45	5	12.5	41.7			195.8	61	94	54.2	4	6	6	14
Project 2007-02 Operating Personnel Communications Protocols (ACTIVE)	3 - Requires developing new requirements in support of blackout recommendation #26 to ensure that real-time system operators use standard communication protocols during normal and emergency operations. COM-003.	50	75	70.8	25	25	5	4.2	0			195.8	74	94	4.2	5	1	2	29
Project 2012-06 Generator Capabilities	40 - For all synchronous generators, specify minimum droop settings and frequency response performance. Require proven voltage support and reactive response to a specific level. Related to Frequency Response Initiative. Related to BAL-003 and the Continent Wide Reserve Policy. New standard(s).	50	50	91.7	62.5	37.5	0	0	0			191.7	60	0	0	6	8	34	38
Project 2010-05.1 Phase 1 of Protection Systems: Misoperations (ACTIVE)	25 - Modify current PRC-003 and -004 standards and definitions related to Protection System Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. Does not include SPS and RAS. Related to System Protection Initiative.	50	62.5	62.5	33.3	37.5	5	50	25			175	64	94	75	7	5	5	8
Project 2009-01 Disturbance and Sabotage Reporting (ACTIVE)	15 - This project will entail revision to existing standards CIP-001 and EOP-004. The standards may be merged to eliminate redundancy and provide clarity on sabotage events. EOP-004 has some 'fill-in-the-blank' components to eliminate. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. EOP-004, CIP-001 and CIP-008.	50	66.7	56.1	16.7	16.7	5	50	27.8			172.8	72	94	77.8	8	2	3	7
Project 2012-04 Protection System Commissionning Testing	38 - Establish minimum level of required commissioning testing prior to putting protection systems into service. Related to System Protection Initiative. New standard(s).	50	48.3	67.7	41.7	50	0	0	0			166	56	0	0	9	10	35	39
Project 2010-17 Definition of BES (ACTIVE)	34 - Define the BES as per FERC Order 743.	0	87.5	75	81.3	75	5	37.5	29.2	1.7	From Stakeholder Comments, foundation of standards.	162.5	52	94	68.4	10	18	14	10
Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS	26 - Modify current PRC-012, -014, and -016 standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. May include additional updates to PRC-004 as well Related to System Protection Initiative.	50	42.7	60	40	45	5	33.3	12.5			152.7	54	94	45.8	11	14	11	16
Project 2010-07 Generator Requirements at the Transmission Interface (ACTIVE)	27 - This project proposes changes to the requirements and the addition of new requirements to add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. Multiple standards.	0	75	75	66.7	66.7	5	50	8.3			150	54	94	58.3	12	15	12	13
Project 2006-06 Reliability Coordination (ACTIVE)	2 - Requires upgrading and expanding existing requirements that address reliability coordinator actions to prevent instability, uncontrolled separation or cascading outages. COM-001, COM-002, IRO-001, IRO-002, IRO-005, IRO-014, IRO-015, IRO-016, and IRO-003.	50	33.3	66.7	37.5	37.5	5	4.2	25			150	56	94	29.2	13	11	9	18
Project 2008-02 Undervoltage Load Shedding	12 - Consider consolidating PRC-010-0 (Assessment of the Design and Effectiveness of UVLS Program) and (PRC-022-1 — Under-Voltage Load Shedding Program Performance). Currently missing are any criteria for identifying where UVLS should be installed. The team will utilize the FIDVR (Fault-Induced Delayed Voltage Recovery) Technical Reference Paper in the development of requirements. Related to System Protection Initiative.	50	29.2	70.8	83.3	50	5	0	0			150	42	94	0	14	24	19	32

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	RELIABILITY SORT							
Project Number and Name	**Short Description**	**Addresses an ERO Strategic Priority** (to be completed by NERC Staff) 50 = Yes 0 = No	**Addresses a reliability risk not covered by an existing standard** 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	**Improves one or more existing standards:** 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	**Cost of Implementation** The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Cost of Administration** The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Time Sensitivity** (to be competed by NERC Staff) Number of months until due date, if any	**Addresses compliance issues from NERC Staff or Stakeholders** 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	**Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is** 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	**Other Practicality Concern** (Explanation for the rating must be indicated in the column to the right) (0 to 50)	**Explanation**	**Reliability Score (0 - 250)**	**Cost Consideration Score (0 - 100)**	**Time Sensitivity Score (0 - 100)**	**Practicality Score (0 - 150)**	**Reliability Ranking**	**Cost Consideration Ranking**	**Time Sensitivity Ranking**	**Practicality Ranking**
Project 2010-01 Support Personnel Training	21 - Require the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system. New standard(s).	50	45.8	50	85	41.7	0	0	0			145.8	42	0	0	15	25	37	41
Project 2008-01 Voltage and Reactive Planning and Control (INFORMAL)	11 - This project supports a blackout recommendation. Industry debate is needed on whether there should be a North American standard that requires a specific amount of reserves, or whether requirements for specific reserves should continue to be addressed at the regional level. The requirements in the existing standards need to be upgraded to be more specific in defining voltage and reactive power schedules. Consideration should be given to adding a requirement for the Reliability Coordinator to monitor and take action if reactive power falls outside identified limits. VAR-001 and -002.	0	66.7	78.3	54.2	30	5	35.2	8.3	50	Addressing Reactive Requirements key to reliability of system. Lenght of Time since the reliability need was identified -- Project was identified to address a Blackout Recommendation (elapsed time = 7 years) and FERC Order 693 directives (elapsed time = 4-1/2 years). Subsequently, NERC Transmission Issues Subcommitte.	145	65	94	93.5	16	4	4	3
Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (ACTIVE)	31 - The project includes of modifications to BAL-001 and BAL-002 to support Frequency Response project. Includes Continent-wide Reserve Policy. 5 Year review of BAL-001. Related to Frequency Response Initiative.	0	50	87.5	81.3	31.3	1	8.3	45.8	40	There is a significant disagreement between FERC Staff, NERC Staff and the industry as to what is required under BAL-002. There could also be signifcant cost savings to the industry if the revisions to BAL-001 were to be realized.	137.5	56	100	94.1	17	12	1	2
Project 2010-13-3 Phase 3 of Relay Loadability: Stable Power Swings	30 - Address concerns with Stable Power Swings as identified in the FERC Order on Relay Loadability. Related to System Protection Initiative. New standard(s).	50	41.7	41.7	81.3	68.8	36	5	12.5	50	Relay performance during "stable" swings is complex. Restraint from tripping during stable swings must be balanced with the necessity of separation during unstable swings. The FERC order ignores this.	133.4	33	42	67.5	18	35	27	11
Project 2007-12 Frequency Response (ACTIVE)	9 - Requires entities to provide data needed to model each interconnection's frequency response, as well as establishes Frequency Response Obligation. Related to Frequency Response Initiative. BAL-003.	0	50	79.2	50	75	5	16.7	10	36.7	Frequency response has declined over the years. This issue is a high priority for FERC.	129.2	51	94	63.4	19	20	16	12
Project 2007-09 Generator Verification (ACTIVE)	7 - Requires upgrading existing requirements for generators to verify their capabilities to ensure that accurate data is used in model to assess the bulk electric system. MOD-025, -026, 027; PRC-019 and -024.	0	66.7	62.5	75	45.8	5	10	0			129.2	52	94	10	20	19	15	25
Project 2010-13.2 Phase 2 of Relay Loadability: Generation (INFORMAL)	29 - Draft new standard PRC-025-1 Generator Relay Loadability in compliance with the FERC Order 733 issued March 18, 2010. Related to System Protection Initiative.	50	29.2	50	62.5	50	12	0	0			129.2	42	82	0	21	26	24	34
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (INFORMAL)	16 - The project will establish requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. New standard(s).	0	66.7	58.3	90	85	27	37.5	10	50	Getting industry buy in to the deveopment of the tool required.	125	38	57	97.5	22	32	25	1
Project 2009-03 Emergency Operations (INFORMAL)	17 - This set of EOP standards may be merged into a single standard. There are some requirements in IRO-001 that may be improved and merged into the new EOP standard. EOP-001, -002, -003, IRO-001.	0	45.8	72.7	45	45	5	12.5	29.2	50	Getting the industry to agree to combining the standards into one or two instead of four.	118.5	57	94	91.7	23	9	8	4
Project 2007-07 Vegetation Management (ACTIVE)	6 - Project 2007-07 Vegetation Management Requires upgrading the existing requirements for entities to implement a vegetation management program to prevent transmission outages that adversely impact the reliability of the bulk electric system. FAC-003.	50	4.2	58.3	58.3	45	5	0	0	50	Results-Based Proof-of-Concept	112.5	40	94	50	24	29	20	15
Project 2007-11 Disturbance Monitoring (INFORMAL)	8 - Requires upgrading and expanding existing requirements for entities to install disturbance monitoring equipment and report disturbance data to ensure information is available to analyze bulk power system disturbances. PRC-002, PRC-018.	0	25	72	75	66.7	5	0	0	26.7	High Regional Priority	97	39	94	26.7	25	31	22	20
Project 2012-01 Equipment Monitoring and Diagnostic Devices	35 - Consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures. New standard(s).	0	25	70.8	87.5	62.5	0	0	0			95.8	36	0	0	26	34	41	43
Project 2010-03 Modeling Data	23 - Requires merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. Related to Blackout recommendation and Modeling Initiative. MOD-010 thru -015.	0	41.7	47.7	33.3	33.3	5	0	0			89.4	56	94	0	27	13	10	30
Project 2007-03 Real-time Transmission Operations (ACTIVE)	4 - Requires upgrading and expanding existing requirements that address transmission operator responsibilities to ensure the real-time operating reliability of the transmission assets within the transmission operator's area. PER-001, TOP-001- through TOP-008	0	4.2	66.7	33.3	50	5	50	41.7			70.9	47	94	91.7	28	21	17	5
Project 2008-12 Coordinate Interchange Standards (INFORMAL)	14 - Revise the set of Coordinate Interchange standards to 1) ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange, 2) to address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties, and 3) to address previously identified stakeholder comments and applicable directives from Order 693. INT-001 through -010.	0	45.8	25	41.7	41.7	5	25	1.7			70.8	47	94	26.7	29	22	18	19
Project 2009-04 Phasor Measurements	18 - Supports a blackout recommendation. Several industry studies were issued that need to be analyzed to determine appropriate requirements for a NERC standard. Related to North-American Synchro-Phasor Initiative. New standard(s).	0	66.7	0	50	33.3	0	0	0			66.7	46	0	0	30	23	36	40

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	RELIABILITY SORT							
Project Number and Name	**Short Description**	**Addresses an ERO Strategic Priority** (to be completed by NERC Staff) 50 = Yes 0 = No	**Addresses a reliability risk not covered by an existing standard** 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	**Improves one or more existing standards:** 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	**Cost of Implementation** The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Cost of Administration** The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Time Sensitivity** (to be competed by NERC Staff) Number of months until due date, if any	**Addresses compliance issues from NERC Staff or Stakeholders** 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	**Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is** 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	**Other Practicality Concern** (Explanation for the rating must be indicated in the column to the right) (0 to 50)	**Explanation**	**Reliability Score (0 - 250)**	**Cost Consideration Score (0 - 100)**	**Time Sensitivity Score (0 - 100)**	**Practicality Score (0 - 150)**	**Reliability Ranking**	**Cost Consideration Ranking**	**Time Sensitivity Ranking**	**Practicality Ranking**
Project 2009-05 Resource Adequacy Assessments	19 - Implements recommendations from the Resource and Transmission Adequacy Task Force (RTATF) Report and the Gas/Electricity Interdependency Task Force Report, approved by the NERC Board on June 15, 2004, related to resource adequacy. New standard(s).	50	8.3	0	33.3	25	0	0	0			58.3	38	0	0	31	33	40	42
Project 2012-02 Physical Protection	36 - Consider the development of reliability standards for the safety and protection of essential equipment, buildings and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system. New standard(s).	0	45.8	8.3	91.7	83.3	0	0	0			54.1	20	0	0	32	37	42	44
Project 2010-04 Demand Data	24 - As envisioned, this project will result in two standards — with MOD-016 through MOD-020 being merged into a single standard, and MOD-021 remaining as a separate standard. The requirements need to be more specific to clearly identify the format, etc., for providing data.	0	0	51.7	18.8	18.8	5	0	0			51.7	54	94	0	33	16	13	31
Project 2010-16 Definition of System Operator	33 - Refine definition of "System Operator" to exclude the Generator Operator, as all other "System Operators" have a more wide-area view.	0	8.3	25	33.3	37.5	0	4.2	0	3.3	From Stakeholder Comments, foundation of standards.	33.3	41	0	7.5	34	27	38	27
Project 2010-08 Functional Model Glossary Revisions	28 - The Functional Model Working Group (FMWG) has received many comments and questions from stakeholders concerning the differences in definitions between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards. This project is designed to address these comments and make the definitions of functional entities consistent between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards.	0	0	29.2	33.3	33.3	0	0	0	12	Foundational piece of ERO	29.2	41	0	12	35	28	39	24
Project 2010-02 Connecting New Facilities to the Grid	22 - Ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standard. FAC-001 and -002.	0	0	25	33.3	33.3	5	0	0			25	40	94	0	36	30	21	33
Project 2012-14 Risk Analysis	47 - Require entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist should include things like GMD, voltage collapse, and other extreme events. New standard(s).	0	25	0	100	50	0	0	0			25	19	0	0	37	38	43	45
Project 2012-07 Obsolescence Review	41 - Require all TOs and GOs to periodically review their electronic, electric, mechanical, and other control systems, as well as protection systems, to replace obsolete equipment. New standard(s).	0	25	0	100	75	0	0	0			25	13	0	0	38	39	44	46
Project 2010-14.1 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent (INFORMAL)	32 - The project includes elimination of Time Error Corrections, 5-year review of BAL-005, miscellaneous clean up and modification to BAL-006.	0	4.2	0	50	50	5	0	25			4.2	26	94	25	39	36	23	21
Project 2012-11 FAC Review	44 - 5-Year Review of FAC-010, -011, -014	0	0	0	50	50	27	0	0			0	0	57	0	40	40	26	35
Project 2012-05 ATC-Revisions - Order 729	39 - Respond to directives in Order 729 related to ATC Standards. Perform 5-year review of MOD-001, -004, -008, -029, and -030. Also includes MOD-028.	0	0	0	50	50	51	0	25			0	0	17	25	41	41	31	22
Project 2012-09 IRO Review	43 - 5-Year review of IRO-006, -008, -009, and -010.	0	0	0	50	50	54	16.7	8.3			0	0	12	25	42	42	32	23
Project 2012-13 NUC Review	46 - 5-Year Review of NUC-001.	0	0	0	25	25	39	0	0			0	0	37	0	43	43	28	36
Project 2012-12 PER Review	45 - 5-Year Review of PER-003, -004 and -005.	0	0	0	50	50	49	0	0			0	0	20	0	44	44	30	37
Project 2012-03 PRC-004 VSLs	37 - Update VSLs to address the situation where Corrective Action Plans were developed or documented, but not fully implemented. PRC-004.	0	0	0	25	50	0	8.3	0			0	0	0	8.3	45	45	45	26
Project 2012-08 Glossary Updates	42 - Per FERC Order 693, define Bulk Power System, Reliability Standard, and Reliable Operation. Modify definition of Generator Operator and Transmission Operator.	0	0	0	75	75	0	4.2	0	3.3	From Stakeholder Comments, foundation of standards.	0	0	0	7.5	46	46	46	28
Project 2006-06.2 Phase 2 of Reliability Coordination	NA - Address specific directives from FERC Order 693 related to reliability standard IRO-003-2 - Reliability Coordination - Wide-Area View											0	0	0	0	47	47	47	47
Project 2012-15 Flow Limited Paths	NA - Address concerns identified with MOD-029 and its treatment of flow-limited paths.											0	0	0	0	48	48	48	48

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	TIME SENSITIVITY SORT							
Project Number and Name	**Short Description**	**Addresses an ERO Strategic Priority** (to be completed by NERC Staff) 50 = Yes 0 = No	**Addresses a reliability risk not covered by an existing standard** 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	**Improves one or more existing standards:** 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	**Cost of Implementation** The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Cost of Administration** The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Time Sensitivity** (to be competed by NERC Staff) Number of months until due date, if any	**Addresses compliance issues from NERC Staff or Stakeholders** 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	**Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is** 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	**Other Practicality Concern** (Explanation for the rating must be indicated in the column to the right) (0 to 50)	**Explanation**	**Reliability Score (0 - 250)**	**Cost Consideration Score (0 - 100)**	**Time Sensitivity Score (0 - 100)**	**Practicality Score (0 - 150)**	**Reliability Ranking**	**Cost Consideration Ranking**	**Time Sensitivity Ranking**	**Practicality Ranking**
Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (ACTIVE)	31 - The project includes of modifications to BAL-001 and BAL-002 to support Frequency Response project. Includes Continent-wide Reserve Policy. 5 Year review of BAL-001. Related to Frequency Response Initiative.	0	50	87.5	81.3	31.3	1	8.3	45.8	40	There is a significant disagreement between FERC Staff, NERC Staff and the industry as to what is required under BAL-002. There could also be signifcant cost savings to the industry if the revisions to BAL-001 were to be realized.	137.5	56	100	94.1	17	12	1	2
Project 2007-17 Protection System Maintenance & Testing (ACTIVE)	10 - Intended to consolidate several standards into a single maintenance and testing standard: PRC-005 (Transmission and Generation Protection System Maintenance and Testing), PRC-008-0 (Underfrequency Load Shedding Equipment Maintenance Programs), PRC-011-0 (UVLS System Maintenance and Testing), and PRC-017-0 (Special Protection System Maintenance and Testing). Standards PRC-008-0, PRC-011-0, and PRC-017-0 would then be withdrawn. Related to System Protection Initiative.	50	50	100	60	50	5	45.8	25			200	60	94	70.8	3	7	2	9
Project 2007-06 System Protection Coordination (ACTIVE)	5 - Requires upgrading and expanding the existing requirements from PRC-001 to identify criteria for determining where to install protection system devices and for requiring the installation of those devices to protect the reliability of the bulk electric system. PRC-027. Related to System Protection Initiative.	50	62.5	83.3	55	45	5	12.5	41.7			195.8	61	94	54.2	4	6	3	14
Project 2007-02 Operating Personnel Communications Protocols (ACTIVE)	3 - Requires developing new requirements in support of blackout recommendation #26 to ensure that real-time system operators use standard communication protocols during normal and emergency operations. COM-003.	50	75	70.8	25	25	5	4.2	0			195.8	74	94	4.2	5	1	4	29
Project 2010-05.1 Phase 1 of Protection Systems: Misoperations (ACTIVE)	25 - Modify current PRC-003 and -004 standards and definitions related to Protection System Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. Does not include SPS and RAS. Related to System Protection Initiative.	50	62.5	62.5	33.3	37.5	5	50	25			175	64	94	75	7	5	5	8
Project 2009-01 Disturbance and Sabotage Reporting (ACTIVE)	15 - This project will entail revision to existing standards CIP-001 and EOP-004. The standards may be merged to eliminate redundancy and provide clarity on sabotage events. EOP-004 has some 'fill-in-the-blank' components to eliminate. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. EOP-004, CIP-001 and CIP-008.	50	66.7	56.1	16.7	16.7	5	50	27.8			172.8	72	94	77.8	8	2	6	7
Project 2010-17 Definition of BES (ACTIVE)	34 - Define the BES as per FERC Order 743.	0	87.5	75	81.3	75	5	37.5	29.2	1.7	From Stakeholder Comments, foundation of standards.	162.5	52	94	68.4	10	18	7	10
Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS	26 - Modify current PRC-012, -014, and -016 standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. May include additional updates to PRC-004 as well. Related to System Protection Initiative.	50	42.7	60	40	45	5	33.3	12.5			152.7	54	94	45.8	11	14	8	16
Project 2010-07 Generator Requirements at the Transmission Interface (ACTIVE)	27 - This project proposes changes to the requirements and the addition of new requirements to add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. Multiple standards.	0	75	75	66.7	66.7	5	50	8.3			150	54	94	58.3	12	15	9	13
Project 2006-06 Reliability Coordination (ACTIVE)	2 - Requires upgrading and expanding existing requirements that address reliability coordinator actions to prevent instability, uncontrolled separation or cascading outages. COM-001, COM-002, IRO-001, IRO-002, IRO-005, IRO-014, IRO-015, IRO-016, and IRO-003.	50	33.3	66.7	37.5	37.5	5	4.2	25			150	56	94	29.2	13	11	10	18
Project 2008-02 Undervoltage Load Shedding	12 - Consider consolidating PRC-010-0 (Assessment of the Design and Effectiveness of UVLS Program) and (PRC-022-1 — Under-Voltage Load Shedding Program Performance). Currently missing are any criteria for identifying where UVLS should be installed. The team will utilize the FIDVR (Fault-Induced Delayed Voltage Recovery) Technical Reference Paper in the development of requirements. Related to System Protection Initiative.	50	29.2	70.8	83.3	50	5	0	0			150	42	94	0	14	24	11	32
Project 2008-01 Voltage and Reactive Planning and Control (INFORMAL)	11 - This project supports a blackout recommendation. Industry debate is needed on whether there should be a North American standard that requires a specific amount of reserves, or whether requirements for specific reserves should continue to be addressed at the regional level. The requirements in the existing standards need to be upgraded to be more specific in defining voltage and reactive power schedules. Consideration should be given to adding a requirement for the Reliability Coordinator to monitor and take action if reactive power falls outside identified limits. VAR-001 and -002.	0	66.7	78.3	54.2	30	5	35.2	8.3	50	Addressing Reactive Requirements key to reliability of system. Lenght of Time since the reliability need was identified -- Project was identified to address a Blackout Recommendation (elapsed time = 7 years) and FERC Order 693 directives (elapsed time = 4-1/2 years). Subsequently, NERC Transmission Issues Subcommitte.	145	65	94	93.5	16	4	12	3
Project 2007-12 Frequency Response (ACTIVE)	9 - Requires entities to provide data needed to model each interconnection's frequency response, as well as establishes Frequency Response Obligation. Related to Frequency Response Initiative. BAL-003.	0	50	79.2	50	75	5	16.7	10	36.7	Frequency response has declined over the years. This issue is a high priority for FERC.	129.2	51	94	63.4	19	20	13	12

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization

TIME SENSITIVITY SORT

Project Number and Name	Short Description	(E) Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	(F) Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	(G) Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	(H) Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(I) Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	(J) Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	(K) Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	(L) Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	(M) Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	(N) Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Reliability Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Ranking
Project 2007-09 Generator Verification (ACTIVE)	7 - Requires upgrading existing requirements for generators to verify their capabilities to ensure that accurate data is used in model to assess the bulk electric system. MOD-025, -026, 027; PRC-019 and -024.	0	66.7	62.5	75	45.8	5	10	0			129.2	52	94	10	20	19	14	25
Project 2009-03 Emergency Operations (INFORMAL)	17 - This set of EOP standards may be merged into a single standard. There are some requirements in IRO-001 that may be improved and merged into the new EOP standard. EOP-001, -002, -003, IRO-001.	0	45.8	72.7	45	45	5	12.5	29.2	50	Getting the industry to agree to combining the standards into one or two instead of four.	118.5	57	94	91.7	23	9	15	4
Project 2007-07 Vegetation Management (ACTIVE)	6 - Project 2007-07 Vegetation Management Requires upgrading the existing requirements for entities to implement a vegetation management program to prevent transmission outages that adversely impact the reliability of the bulk electric system. FAC-003.	50	4.2	58.3	58.3	45	5	0	0	50	Results-Based Proof-of-Concept	112.5	40	94	50	24	29	16	15
Project 2007-11 Disturbance Monitoring (INFORMAL)	8 - Requires upgrading and expanding existing requirements for entities to install disturbance monitoring equipment and report disturbance data to ensure information is available to analyze bulk power system disturbances. PRC-002, PRC-018.	0	25	72	75	66.7	5	0	0	26.7	High Regional Priority	97	39	94	26.7	25	31	17	20
Project 2010-03 Modeling Data	23 - Requires merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. Related to Blackout recommendation and Modeling Initiative. MOD-010 thru -015.	0	41.7	47.7	33.3	33.3	5	0	0			89.4	56	94	0	27	13	18	30
Project 2007-03 Real-time Transmission Operations (ACTIVE)	4 - Requires upgrading and expanding existing requirements that address transmission operator responsibilities to ensure the real-time operating reliability of the transmission assets within the transmission operator's area. PER-001, TOP-001-through TOP-008	0	4.2	66.7	33.3	50	5	50	41.7			70.9	47	94	91.7	28	21	19	5
Project 2008-12 Coordinate Interchange Standards (INFORMAL)	14 - Revise the set of Coordinate Interchange standards to 1) ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange, 2) to address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties, and 3) to address previously identified stakeholder comments and applicable directives from Order 693. INT-001 through -010.	0	45.8	25	41.7	41.7	5	25	1.7			70.8	47	94	26.7	29	22	20	19
Project 2010-04 Demand Data	24 - As envisioned, this project will result in two standards — with MOD-016 through MOD-020 being merged into a single standard, and MOD-021 remaining as a separate standard. The requirements need to be more specific to clearly identify the format, etc., for providing data.	0	0	51.7	18.8	18.8	5	0	0			51.7	54	94	0	33	16	21	31
Project 2010-02 Connecting New Facilities to the Grid	22 - Ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standard. FAC-001 and -002.	0	0	25	33.3	33.3	5	0	0			25	40	94	0	36	30	22	33
Project 2010-14.1 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent (INFORMAL)	32 - The project includes elimination of Time Error Corrections, 5-year review of BAL-005, miscellaneous clean up and modification to BAL-006.	0	4.2	0	50	50	5	0	25			4.2	26	94	25	39	36	23	21
Project 2010-13.2 Phase 2 of Relay Loadability: Generation (INFORMAL)	29 - Draft new standard PRC-025-1 Generator Relay Loadability in compliance with the FERC Order 733 issued March 18, 2010. Related to System Protection Initiative.	50	29.2	50	62.5	50	12	0	0			129.2	42	82	0	21	26	24	34
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (INFORMAL)	16 - The project will establish requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. New standard(s).	0	66.7	58.3	90	85	27	37.5	10	50	Getting industry buy in to the deveopment of the tool required.	125	38	57	97.5	22	32	25	1
Project 2012-11 FAC Review	44 - 5-Year Review of FAC-010, -011, -014	0	0	0	50	50	27	0	0			0	0	57	0	40	40	26	35
Project 2010-13-3 Phase 3 of Relay Loadability: Stable Power Swings	30 - Address concerns with Stable Power Swings as identified in the FERC Order on Relay Loadability. Related to System Protection Initiative. New standard(s).	50	41.7	41.7	81.3	68.8	36	5	12.5	50	Relay performance during "stable" swings is complex. Restraint from tripping during stable swings must be balanced with the necessity of separation during unstable swings. The FERC order ignores this.	133.4	33	42	67.5	18	35	27	11
Project 2012-13 NUC Review	46 - 5-Year Review of NUC-001.	0	0	0	25	25	39	0	0			0	0	37	0	43	43	28	36
Project 2008-06 Cyber Security - Order 706 (ACTIVE)	13 - The project requires modifications to CIP-002 thru CIP-009 to bring the standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706.	50	70.8	100	87.5	75	48	45.8	45.8			220.8	52	22	91.6	2	17	29	6
Project 2012-12 PER Review	45 - 5-Year Review of PER-003, -004 and -005.	0	0	0	50	50	49	0	0			0	0	20	0	44	44	30	37
Project 2012-05 ATC-Revisions - Order 729	39 - Respond to directives in Order 729 related to ATC Standards. Perform 5-year review of MOD-001, -004, -008, -029, and -030. Also includes MOD-028.	0	0	0	50	50	51	0	25			0	0	17	25	41	41	31	22
Project 2012-09 IRO Review	43 - 5-Year review of IRO-006, -008, -009, and -010.	0	0	0	50	50	54	16.7	8.3			0	0	12	25	42	42	32	23

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	TIME SENSITIVITY SORT							
Project Number and Name	Short Description	Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Reliability Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Ranking
Project 2009-07 Reliability of Protection Systems	20 - Requires facility owners to have protection system equipment installed such that, if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards. Related to System Protection Initiative. New standard(s).	50	83.3	88.3	66.7	41.7	0	12.5	25			221.6	66	0	37.5	1	3	33	17
Project 2012-06 Generator Capabilities	40 - For all synchronous generators, specify minimum droop settings and frequency response performance. Require proven voltage support and reactive response to a specific level. Related to Frequency Response Initiative. Related to BAL-003 and the Continent Wide Reserve Policy. New standard(s).	50	50	91.7	62.5	37.5	0	0	0			191.7	60	0	0	6	8	34	38
Project 2012-04 Protection System Commissionning Testing	38 - Establish minimum level of required commissioning testing prior to putting protection systems into service. Related to System Protection Initiative. New standard(s).	50	48.3	67.7	41.7	50	0	0	0			166	56	0	0	9	10	35	39
Project 2010-01 Support Personnel Training	21 - Require the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system. New standard(s).	50	45.8	50	85	41.7	0	0	0			145.8	42	0	0	15	25	36	41
Project 2012-01 Equipment Monitoring and Diagnostic Devices	35 - Consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures. New standard(s).	0	25	70.8	87.5	62.5	0	0	0			95.8	36	0	0	26	34	37	43
Project 2009-04 Phasor Measurements	18 - Supports a blackout recommendation. Several industry studies were issued that need to be analyzed to determine appropriate requirements for a NERC standard. Related to North-American Synchro-Phasor Initiative. New standard(s).	0	66.7	0	50	33.3	0	0	0			66.7	46	0	0	30	23	38	40
Project 2009-05 Resource Adequacy Assessments	19 - Implements recommendations from the Resource and Transmission Adequacy Task Force (RTATF) Report and the Gas/Electricity Interdependency Task Force Report, approved by the NERC Board on June 15, 2004, related to resource adequacy. New standard(s).	50	8.3	0	33.3	25	0	0	0			58.3	38	0	0	31	33	39	42
Project 2012-02 Physical Protection	36 - Consider the development of reliability standards for the safety and protection of essential equipment, buildings and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system. New standard(s).	0	45.8	8.3	91.7	83.3	0	0	0			54.1	20	0	0	32	37	40	44
Project 2010-16 Definition of System Operator	33 - Refine definition of "System Operator" to exclude the Generator Operator, as all other "System Operators" have a more wide-area view.	0	8.3	25	33.3	37.5	0	4.2	0	3.3	From Stakeholder Comments, foundation of standards.	33.3	41	0	7.5	34	27	41	27
Project 2010-08 Functional Model Glossary Revisions	28 - The Functional Model Working Group (FMWG) has received many comments and questions from stakeholders concerning the differences in definitions between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards. This project is designed to address these comments and make the definitions of functional entities consistent between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards.	0	0	29.2	33.3	33.3	0	0	0	12	Foundational piece of ERO	29.2	41	0	12	35	28	42	24
Project 2012-14 Risk Analysis	47 - Require entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist should include things like GMD, voltage collapse, and other extreme events. New standard(s).	0	25	0	100	50	0	0	0			25	19	0	0	37	38	43	45
Project 2012-07 Obsolescence Review	41 - Require all TOs and GOs to periodically review their electronic, electric, mechanical, and other control systems, as well as protection systems, to replace obsolete equipment. New standard(s).	0	25	0	100	75	0	0	0			25	13	0	0	38	39	44	46
Project 2012-03 PRC-004 VSLs	37 - Update VSLs to address the situation where Corrective Action Plans were developed or documented, but not fully implemented. PRC-004.	0	0	0	25	50	0	8.3	0			0	0	0	8.3	45	45	45	26
Project 2012-08 Glossary Updates	42 - Per FERC Order 693, define Bulk Power System, Reliability Standard, and Reliable Operation. Modify definition of Generator Operator and Transmission Operator.	0	0	0	75	75	0	4.2	0	3.3	From Stakeholder Comments, foundation of standards.	0	0	0	7.5	46	46	46	28
Project 2006-06.2 Phase 2 of Reliability Coordination	NA - Address specific directives from FERC Order 693 related to reliability standard IRO-003-2 - Reliability Coordination - Wide-Area View											0	0	0	0	47	47	47	47
Project 2012-15 Flow Limited Paths	NA - Address concerns identified with MOD-029 and its treatment of flow-limited paths.											0	0	0	0	48	48	48	48

STANDARDS COMMITTEE Reliability Standard Project Prioritization		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	PRACTICALITY SORT							
Project Number and Name	Short Description	**Addresses an ERO Strategic Priority** (to be completed by NERC Staff) 50 = Yes 0 = No	**Addresses a reliability risk not covered by an existing standard** 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	**Improves one or more existing standards:** 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	**Cost of Implementation** The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Cost of Administration** The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Time Sensitivity** (to be competed by NERC Staff) Number of months until due date, if any	**Addresses compliance issues from NERC Staff or Stakeholders** 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	**Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is** 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	**Other Practicality Concern** (Explanation for the rating must be indicated in the column to the right) (0 to 50)	Explanation	**Reliability Score (0 - 250)**	**Cost Consideration Score (0 - 100)**	**Time Sensitivity Score (0 - 100)**	**Practicality Score (0 - 150)**	**Reliability Ranking**	**Cost Consideration Ranking**	**Time Sensitivity Ranking**	**Practicality Ranking**
Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (INFORMAL)	16 - The project will establish requirements for the functionality, performance, and management of Real-time tools for Reliability Coordinators, Transmission Operators, and Balancing Authorities for use by their System Operators in support of reliable System operations. New standard(s).	0	66.7	58.3	90	85	27	37.5	10	50	Getting industry buy in to the deveopment of the tool required.	125	38	57	97.5	22	32	25	1
Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (ACTIVE)	31 - The project includes of modifications to BAL-001 and BAL-002 to support Frequency Response project. Includes Continent-wide Reserve Policy. 5 Year review of BAL-001. Related to Frequency Response Initiative.	0	50	87.5	81.3	31.3	1	8.3	45.8	40	There is a significant disagreement between FERC Staff, NERC Staff and the industry as to what is required under BAL-002. There could also be signifcant cost savings to the industry if the revisions to BAL-001 were to be realized.	137.5	56	100	94.1	17	12	1	2
Project 2008-01 Voltage and Reactive Planning and Control (INFORMAL)	11 - This project supports a blackout recommendation. Industry debate is needed on whether there should be a North American standard that requires a specific amount of reserves, or whether requirements for specific reserves should continue to be addressed at the regional level. The requirements in the existing standards need to be upgraded to be more specific in defining voltage and reactive power schedules. Consideration should be given to adding a requirement for the Reliability Coordinator to monitor and take action if reactive power falls outside identified limits. VAR-001 and -002.	0	66.7	78.3	54.2	30	5	35.2	8.3	50	Addressing Reactive Requirements key to reliability of system. Lenght of Time since the reliability need was identified -- Project was identified to address a Blackout Recommendation (elapsed time = 7 years) and FERC Order 693 directives (elapsed time = 4-1/2 years). Subsequently, NERC Transmission Issues Subcommitte.	145	65	94	93.5	16	4	12	3
Project 2009-03 Emergency Operations (INFORMAL)	17 - This set of EOP standards may be merged into a single standard. There are some requirements in IRO-001 that may be improved and merged into the new EOP standard. EOP-001, -002, -003, IRO-001.	0	45.8	72.7	45	45	5	12.5	29.2	50	Getting the industry to agree to combining the standards into one or two instead of four.	118.5	57	94	91.7	23	9	15	4
Project 2007-03 Real-time Transmission Operations (ACTIVE)	4 - Requires upgrading and expanding existing requirements that address transmission operator responsibilities to ensure the real-time operating reliability of the transmission assets within the transmission operator's area. PER-001, TOP-001-through TOP-008	0	4.2	66.7	33.3	50	5	50	41.7			70.9	47	94	91.7	28	21	19	5
Project 2008-06 Cyber Security - Order 706 (ACTIVE)	13 - The project requires modifications to CIP-002 thru CIP-009 to bring the standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706.	50	70.8	100	87.5	75	48	45.8	45.8			220.8	52	22	91.6	2	17	29	6
Project 2009-01 Disturbance and Sabotage Reporting (ACTIVE)	15 - This project will entail revision to existing standards CIP-001 and EOP-004. The standards may be merged to eliminate redundancy and provide clarity on sabotage events. EOP-004 has some 'fill-in-the-blank' components to eliminate. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. EOP-004, CIP-001 and CIP-008.	50	66.7	56.1	16.7	16.7	5	50	27.8			172.8	72	94	77.8	8	2	6	7
Project 2010-05.1 Phase 1 of Protection Systems: Misoperations (ACTIVE)	25 - Modify current PRC-003 and -004 standards and definitions related to Protection System Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. Does not include SPS and RAS. Related to System Protection Initiative.	50	62.5	62.5	33.3	37.5	5	50	25			175	64	94	75	7	5	5	8
Project 2007-17 Protection System Maintenance & Testing (ACTIVE)	10 - Intended to consolidate several standards into a single maintenance and testing standard: PRC-005 (Transmission and Generation Protection System Maintenance and Testing), PRC-008-0 (Underfrequency Load Shedding Equipment Maintenance Programs), PRC-011-0 (UVLS System Maintenance and Testing), and PRC-017-0 (Special Protection System Maintenance and Testing). Standards PRC-008-0, PRC-011-0, and PRC-017-0 would then be withdrawn. Related to System Protection Initiative.	50	50	100	60	50	5	45.8	25			200	60	94	70.8	3	7	2	9
Project 2010-17 Definition of BES (ACTIVE)	34 - Define the BES as per FERC Order 743.	0	87.5	75	81.3	75	5	37.5	29.2	1.7	From Stakeholder Comments, foundation of standards.	162.5	52	94	68.4	10	18	7	10
Project 2010-13-3 Phase 3 of Relay Loadability: Stable Power Swings	30 - Address concerns with Stable Power Swings as identified in the FERC Order on Relay Loadability. Related to System Protection Initiative. New standard(s).	50	41.7	41.7	81.3	68.8	36	5	12.5	50	Relay performance during "stable" swings is complex. Restraint from tripping during stable swings must be balanced with the necessity of separation during unstable swings. The FERC order ignores this.	133.4	33	42	67.5	18	35	27	11
Project 2007-12 Frequency Response (ACTIVE)	9 - Requires entities to provide data needed to model each interconnection's frequency response, as well as establishes Frequency Response Obligation. Related to Frequency Response Initiative, BAL-003.	0	50	79.2	50	75	5	16.7	10	36.7	Frequency response has declined over the years. This issue is a high priority for FERC.	129.2	51	94	63.4	19	20	13	12
Project 2010-07 Generator Requirements at the Transmission Interface (ACTIVE)	27 - This project proposes changes to the requirements and the addition of new requirements to add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. Multiple standards.	0	75	75	66.7	66.7	5	50	8.3			150	54	94	58.3	12	15	9	13

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	PRACTICALITY SORT							
Project Number and Name	**Short Description**	**Addresses an ERO Strategic Priority** (to be completed by NERC Staff) 50 = Yes 0 = No	**Addresses a reliability risk not covered by an existing standard** 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	**Improves one or more existing standards:** 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	**Cost of Implementation** The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Cost of Administration** The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Time Sensitivity** (to be competed by NERC Staff) Number of months until due date, if any	**Addresses compliance issues from NERC Staff or Stakeholders** 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	**Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is** 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	**Other Practicality Concern** (Explanation for the rating must be indicated in the column to the right) (0 to 50)	**Explanation**	**Reliability Score (0 - 250)**	**Cost Consideration Score (0 - 100)**	**Time Sensitivity Score (0 - 100)**	**Practicality Score (0 - 150)**	**Reliability Ranking**	**Cost Consideration Ranking**	**Time Sensitivity Ranking**	**Practicality Ranking**
Project 2007-06 System Protection Coordination (ACTIVE)	5 - Requires upgrading and expanding the existing requirements from PRC-001 to identify criteria for determining where to install protection system devices and for requiring the installation of those devices to protect the reliability of the bulk electric system. PRC-027. Related to System Protection Initiative.	50	62.5	83.3	55	45	5	12.5	41.7			195.8	61	94	54.2	4	6	3	14
Project 2007-07 Vegetation Management (ACTIVE)	6 - Project 2007-07 Vegetation Management Requires upgrading the existing requirements for entities to implement a vegetation management program to prevent transmission outages that adversely impact the reliability of the bulk electric system. FAC-003.	50	4.2	58.3	58.3	45	5	0	0	50	Results-Based Proof-of-Concept	112.5	40	94	50	24	29	16	15
Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS	26 - Modify current PRC-012, -014, and -016 standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. May include additional updates to PRC-004 as well. Related to System Protection Initiative.	50	42.7	60	40	45	5	33.3	12.5			152.7	54	94	45.8	11	14	8	16
Project 2009-07 Reliability of Protection Systems	20 - Requires facility owners to have protection system equipment installed such that, if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards. Related to System Protection Initiative. New standard(s).	50	83.3	88.3	66.7	41.7	0	12.5	25			221.6	66	0	37.5	1	3	33	17
Project 2006-06 Reliability Coordination (ACTIVE)	2 - Requires upgrading and expanding existing requirements that address reliability coordinator actions to prevent instability, uncontrolled separation or cascading outages. COM-001, COM-002, IRO-001, IRO-002, IRO-005, IRO-014, IRO-015, IRO-016, and IRO-003.	50	33.3	66.7	37.5	37.5	5	4.2	25			150	56	94	29.2	13	11	10	18
Project 2007-11 Disturbance Monitoring (INFORMAL)	8 - Requires upgrading and expanding existing requirements for entities to install disturbance monitoring equipment and report disturbance data to ensure information is available to analyze bulk power system disturbances. PRC-002, PRC-018.	0	25	72	75	66.7	5	0	0	26.7	High Regional Priority	97	39	94	26.7	25	31	17	19
Project 2008-12 Coordinate Interchange Standards (INFORMAL)	14 - Revise the set of Coordinate Interchange standards to 1) ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange, 2) to address the Interchange Subcommittee's concerns related to the Dynamic Transfers and Pseudo-ties, and 3) to address previously identified stakeholder comments and applicable directives from Order 693. INT-001 through -010.	0	45.8	25	41.7	41.7	5	25	1.7			70.8	47	94	26.7	29	22	20	20
Project 2010-14.1 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent (INFORMAL)	32 - The project includes elimination of Time Error Corrections, 5-year review of BAL-005, miscellaneous clean up and modification to BAL-006.	0	4.2	0	50	50	5	0	25			4.2	26	94	25	39	36	23	21
Project 2012-05 ATC-Revisions - Order 729	39 - Respond to directives in Order 729 related to ATC Standards. Perform 5-year review of MOD-001, -004, -008, -029, and -030. Also includes MOD-028.	0	0	0	50	50	51	0	25			0	0	17	25	41	41	31	22
Project 2012-09 IRO Review	43 - 5-Year review of IRO-006, -008, -009, and -010.	0	0	0	50	50	54	16.7	8.3			0	0	12	25	42	42	32	23
Project 2010-08 Functional Model Glossary Revisions	28 - The Functional Model Working Group (FMWG) has received many comments and questions from stakeholders concerning the differences in definitions between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards. This project is designed to address these comments and make the definitions of functional entities consistent between the Functional Model and the NERC Glossary of Terms Used in Reliability Standards.	0	0	29.2	33.3	33.3	0	0	0	12	Foundational piece of ERO	29.2	41	0	12	35	28	42	24
Project 2007-09 Generator Verification (ACTIVE)	7 - Requires upgrading existing requirements for generators to verify their capabilities to ensure that accurate data is used in model to assess the bulk electric system. MOD-025, -026, 027; PRC-019 and -024.	0	66.7	62.5	75	45.8	5	10	0			129.2	52	94	10	20	19	14	25
Project 2012-03 PRC-004 VSLs	37 - Update VSLs to address the situation where Corrective Action Plans were developed or documented, but not fully implemented. PRC-004.	0	0	0	25	50	0	8.3	0			0	0	0	8.3	45	45	45	26
Project 2010-16 Definition of System Operator	33 - Refine definition of "System Operator" to exclude the Generator Operator, as all other "System Operators" have a more wide-area view.	0	8.3	25	33.3	37.5	0	4.2	0	3.3	From Stakeholder Comments, foundation of standards.	33.3	41	0	7.5	34	27	41	27
Project 2012-08 Glossary Updates	42 - Per FERC Order 693, define Bulk Power System, Reliability Standard, and Reliable Operation. Modify definition of Generator Operator and Transmission Operator.	0	0	0	75	75	0	4.2	0	3.3	From Stakeholder Comments, foundation of standards.	0	0	0	7.5	46	46	46	28
Project 2007-02 Operating Personnel Communications Protocols (ACTIVE)	3 - Requires developing new requirements in support of blackout recommendation #26 to ensure that real-time system operators use standard communication protocols during normal and emergency operations. COM-003.	50	75	70.8	25	25	5	4.2	0			195.8	74	94	4.2	5	1	4	29

NERC Standards Committee
Project Prioritization Worksheet

STANDARDS COMMITTEE Reliability Standard Project Prioritization		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	PRACTICALITY SORT							
Project Number and Name	**Short Description**	**Addresses an ERO Strategic Priority** (to be completed by NERC Staff) 50 = Yes 0 = No	**Addresses a reliability risk not covered by an existing standard** 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	**Improves one or more existing standards:** 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	**Cost of Implementation** The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Cost of Administration** The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	**Time Sensitivity** (to be competed by NERC Staff) Number of months until due date, if any	**Addresses compliance issues from NERC Staff or Stakeholders** 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	**Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is** 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	**Other Practicality Concern** (Explanation for the rating must be indicated in the column to the right) (0 to 50)	**Explanation**	**Reliability Score (0 - 250)**	**Cost Consideration Score (0 - 100)**	**Time Sensitivity Score (0 - 100)**	**Practicality Score (0 - 150)**	**Reliability Ranking**	**Cost Consideration Ranking**	**Time Sensitivity Ranking**	**Practicality Ranking**
Project 2008-02 Undervoltage Load Shedding	12 - Consider consolidating PRC-010-0 (Assessment of the Design and Effectiveness of UVLS Program) and (PRC-022-1 — Under-Voltage Load Shedding Program Performance). Currently missing are any criteria for identifying where UVLS should be installed. The team will utilize the FIDVR (Fault-Induced Delayed Voltage Recovery) Technical Reference Paper in the development of requirements. Related to System Protection Initiative.	50	29.2	70.8	83.3	50	5	0	0			150	42	94	0	14	24	11	30
Project 2010-03 Modeling Data	23 - Requires merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. Related to Blackout recommendation and Modeling Initiative. MOD-010 thru -015.	0	41.7	47.7	33.3	33.3	5	0	0			89.4	56	94	0	27	13	18	31
Project 2010-04 Demand Data	24 - As envisioned, this project will result in two standards — with MOD-016 through MOD-020 being merged into a single standard, and MOD-021 remaining as a separate standard. The requirements need to be more specific to clearly identify the format, etc., for providing data.	0	0	51.7	18.8	18.8	5	0	0			51.7	54	94	0	33	16	21	32
Project 2010-02 Connecting New Facilities to the Grid	22 - Ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standard. FAC-001 and -002.	0	0	25	33.3	33.3	5	0	0			25	40	94	0	36	30	22	33
Project 2010-13.2 Phase 2 of Relay Loadability: Generation (INFORMAL)	29 - Draft new standard PRC-025-1 Generator Relay Loadability in compliance with the FERC Order 733 issued March 18, 2010. Related to System Protection Initiative.	50	29.2	50	62.5	50	12	0	0			129.2	42	82	0	21	26	24	34
Project 2012-11 FAC Review	44 - 5-Year Review of FAC-010, -011, -014	0	0	0	50	50	27	0	0			0	0	57	0	40	40	26	35
Project 2012-13 NUC Review	46 - 5-Year Review of NUC-001.	0	0	0	25	25	39	0	0			0	0	37	0	43	43	28	36
Project 2012-12 PER Review	45 - 5-Year Review of PER-003, -004 and -005.	0	0	0	50	50	49	0	0			0	0	20	0	44	44	30	37
Project 2012-06 Generator Capabilities	40 - For all synchronous generators, specify minimum droop settings and frequency response performance. Require proven voltage support and reactive response to a specific level. Related to Frequency Response Initiative. Related to BAL-003 and the Continent Wide Reserve Policy. New standard(s).	50	50	91.7	62.5	37.5	0	0	0			191.7	60	0	0	6	8	34	38
Project 2012-04 Protection System Commissionning Testing	38 - Establish minimum level of required commissioning testing prior to putting protection systems into service. Related to System Protection Initiative. New standard(s).	50	48.3	67.7	41.7	50	0	0	0			166	56	0	0	9	10	35	39
Project 2010-01 Support Personnel Training	21 - Require the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system. New standard(s).	50	45.8	50	85	41.7	0	0	0			145.8	42	0	0	15	25	36	40
Project 2012-01 Equipment Monitoring and Diagnostic Devices	35 - Consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures. New standard(s).	0	25	70.8	87.5	62.5	0	0	0			95.8	36	0	0	26	34	37	41
Project 2009-04 Phasor Measurements	18 - Supports a blackout recommendation. Several industry studies were issued that need to be analyzed to determine appropriate requirements for a NERC standard. Related to North-American Synchro-Phasor Initiative. New standard(s).	0	66.7	0	50	33.3	0	0	0			66.7	46	0	0	30	23	38	42
Project 2009-05 Resource Adequacy Assessments	19 - Implements recommendations from the Resource and Transmission Adequacy Task Force (RTATF) Report and the Gas/Electricity Interdependency Task Force Report, approved by the NERC Board on June 15, 2004, related to resource adequacy. New standard(s).	50	8.3	0	33.3	25	0	0	0			58.3	38	0	0	31	33	39	43
Project 2012-02 Physical Protection	36 - Consider the development of reliability standards for the safety and protection of essential equipment, buildings and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system. New standard(s).	0	45.8	8.3	91.7	83.3	0	0	0			54.1	20	0	0	32	37	40	44
Project 2012-14 Risk Analysis	47 - Require entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist should include things like GMD, voltage collapse, and other extreme events. New standard(s).	0	25	0	100	50	0	0	0			25	19	0	0	37	38	43	45
Project 2012-07 Obsolescence Review	41 - Require all TOs and GOs to periodically review their electronic, electric, mechanical, and other control systems, as well as protection systems, to replace obsolete equipment. New standard(s).	0	25	0	100	75	0	0	0			25	13	0	0	38	39	44	46
Project 2006-06.2 Phase 2 of Reliability Coordination	NA - Address specific directives from FERC Order 693 related to reliability standard IRO-003-2 - Reliability Coordination - Wide-Area View											0	0	0	0	47	47	47	47
Project 2012-15 Flow Limited Paths	NA - Address concerns identified with MOD-029 and its treatment of flow-limited paths.											0	0	0	0	48	48	48	48

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION



Standards Committee Process for Standards Project Identification, Prioritization, and Monitoring

to ensure the reliability of the bulk power system

Revised July 2011

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

Table of Contents

Objective *3*

Changes in this Revision *3*

Background *4*

1. Identifying the List of Standards Projects 4
2. Identifying NERC Project Capacity 4
3. Identifying the Project Portfolio Mix 5
4. Evaluating Each Project 5
5. Determining Cost Considerations 6
6. Determining Projects for Each Program 6
7. Adding New Projects Intra-year and Adjusting Project Priority 6

Attachment A – Project Prioritization Tool Details 9

Attachment B: Prioritization Tool 13

Objective

This document presents a Standards Committee process for identifying, prioritizing, and monitoring NERC standards development projects, taking into account the various drivers for project initiation and the industry's resource constraints. The process provides the flexibility to accommodate new projects and to adjust project priority and completion schedule in response to changing conditions.

Changes in this Revision

When first used in developing the 2011-2013 Reliability Standard Development Plan (RSDP), the Standards Committee solicited feedback on the use of this tool. Stakeholders submitted several comments and suggestions that the Standards Committee deferred until the development of this revision. In response to those comments and suggestions, as well as other feedback received during the development of this revision, the Standards Committee made the following changes:

- Elimination of the perceived duplication between the process of assigning a score based on the number and type of regulatory directives assigned (previously column G) and the process of assigning scores for "Reliability Gap" (previously column H) and "Reliability Improvement" (previously column I). Some concern has been expressed that ranking the priority of directives assigned to a project based on their reliability impact and then additionally rating a project on its reliability impact was "double counting."
- Addition of a score to account for projects that address ERO Strategic Priorities
- Consolidation of all deadlines (regulatory directive based (previously column F), 5-year review based (column K), or otherwise) into one single new "Time Sensitivity" score. While previously, the Standards Committee felt that time limits derived from directives should be given special consideration, further discussion has led to the questioning of that assertion. Instead, all time limits will be considered, and the Standards Committee may elect to use its judgment to make additional modifications to project prioritization results based on specific knowledge or situations.
- Elimination of the "Project Percent Complete" (previously column N) evaluation
- Addition of two preliminary "cost" considerations
- Modification of the scoring mechanism, such that the "total" score is now the sum of the four subject area scores. In two cases, subject matter scores are no longer simple summations, but instead are determined based on slightly more complex equations.
- The ability to rank projects based on different factors (Reliability, Cost Considerations, Time Sensitivity, Practicality, or all factors combined)

Background

Since the startup of the ERO, the number of standards development projects has been significant. Coupled with the increasing number of requests for interpretations and directives issued by regulatory authorities, the industry has experienced a rapid and sustained increase in standards development related workload. The standards development process allows for any individual to propose a new project or request an interpretation. While the Standards Committee can exercise its discretion to delay the start of any project to cope with increased workload and to better manage standard projects to achieve timely completion, additional flexibility beyond just withholding the start of a project is needed.

At its April 2010 meeting, the NERC Standards Committee endorsed a proposal to develop a structured process to assist in managing standards development projects from the project planning stage through submission of a completed standard to the NERC Board of Trustees. The process outlined in this document takes into account industry resource constraints and changing conditions as new projects emerge and as issues are encountered during the course of standard development. It is expected that this process will occur on an annual basis. Projects that are requested mid-cycle will be scored and evaluated as described in Section 7.

1. **Identifying the List of Standards Projects**

   In general, standard projects may be initiated for a variety of reasons, including:

   a. **To meet a deadline.** These deadlines may include the five-year standard revision cycle requirement, regulatory-imposed deadlines, or other time-based commitments.

   b. **To address a Reliability Need** — Industry participants, regulators, NERC staff or the Board of Trustees identify the need for a new standard or revision to an existing standard to meet a reliability need or fill a reliability gap

   c. **To address practical implementation issues.**— Industry participants, NERC and Regional Entity staff identify quality and clarity gaps in NERC's existing reliability standards that need to be remedied to ensure consistent industry compliance. These may be indentified through compliance, through the need for interpretations, or through other means (for example, Regional Entities and stakeholders may propose continent-wide NERC standards that will avoid the need to develop regional standards which will be phased out when the NERC standards are put in place).

   The list of standards projects will include all current projects, all projects in informal development, and all new projects that have yet to be initiated.

   Although any stakeholder can submit a Standards Authorization Request at any time, NERC will generally solicit project candidates for a fixed period of time prior to beginning its annual prioritization. Requests received outside that window of time will be considered for prioritization either at the next annual prioritization or on a case by case basis.

2. **Identifying NERC Project Capacity**

NERC is only able to manage a finite number of projects at a given point in time, due to the limitations of both staff and industry resources. In general, NERC can accommodate 10-12 projects on an ongoing basis. Because some projects are more complex than others, NERC's Standards Committee will work with NERC staff to determine the total capacity for NERC Standards Development. NERC staff will remain responsible for the actual assignment of staff resources to projects.

3. **Identifying the Project Portfolio Mix**

Because there are many legitimate reasons for initiating projects, a simple ranking based on priorities is not sufficient. Although focusing on those projects with the greatest reliability need is important, it does not recognize the practical considerations or the time sensitivity of each project. For example, a project with a low reliability impact may nonetheless be associated with a regulatory imposed deadline; or a project may not directly improve reliability, but make a standard much easier to comprehend and implement successfully.

To address this, the Standards Committee allocates Project Capacity to three programs within the Standards Development portfolio: Time Sensitive projects, Practicality projects, and Reliability projects. This allocation is determined by the Standards Committee each year as the Reliability Standards Development Plan is being drafted. For example, assuming that the SC will pursue a total of 12 projects in 2012, this could result in capacity being allocated for three Time-sensitive projects, three Practicality projects, and six Reliability projects.

4. **Evaluating Each Project**

Each project identified will be evaluated in several areas. Members of the Standards Committee will provide the majority of the evaluation data, while NERC staff will only provide information regarding Time-Sensitivity and alignment with ERO Strategic Priorities (columns E and J in Attachment A).

Each representative on the Standards Committee will provide their recommendations for the values assigned to specific areas of each project. NERC will then aggregate and analyze this information and present it to the Standards Committee for review. In general, the arithmetic mean of all Standards Committee input will be used to set the "score" to be used in the prioritization. So if three members selected 50, 75, and 100 out of a possible total 100, the arithmetic mean would be 75.

However, in those cases where significant disagreement is noted between Standards Committee members, further discussion will occur among the Standards Committee to determine if additional changes should be considered. "Significant" disagreement shall be defined as more than 50% of the Standards Committee members participating having scores that are different from the mean by more than 30% of the maximum value for that particular score. So for example, if three members selected 0, 50, and 100, the mean would be 50. However, 66% (two) of the members would have chosen values that were different from the mean by more than 30% (50 points), so further discussion would be required to reconcile the difference.

5. **Determining Cost Considerations**

   As a first step, all projects will be evaluated for cost considerations. This is accomplished by comparing the "reliability" value to the "cost" value. The calculation of this value is explained in Attachment A's explanation of Column P.

   Cost is measured in two areas – the cost to the industry to comply with the standard, and the cost to the industry to demonstrate compliance with the standard. The first area should be focused on the incremental upgrades and investments needed to meet the standard (e.g., equipment purchases, software upgrades, training), while the second area should consider the cost of retaining data and documents, auditing and audit preparation, and reporting.

   Projects with a score of less than 50 will generally having a lower benefit relative to cost. When contemplating projects for the Reliability Program area, those with a lower benefit should be carefully considered prior to being initiated. However, a lower benefit should generally not by itself preclude a project from consideration.

6. **Determining Projects for Each Program**

   For each of the three portfolio program areas (Time Sensitive, Reliability, or Practicality), the Standards Committee will prioritize the list of projects and assign the top priority projects to the programs until program capacity is eliminated.

   Following this, the Standards Committee will review any projects that are in progress but are not currently assigned to one of the three portfolio programs. In general, the Standards Committee will displace lower priority projects within the program with projects currently in progress – effectively "filling" the programs with active work before adding new work. However, the Standards Committee may, if it so chooses, halt an existing project in order to move a project that it deems more critical forward.

   Next, the Standards Committee will review project interdependencies. If a high-priority project is expected to move forward, and relies on a lower-priority project for completion, then that lower-priority project should displace a higher-priority project to ensure the dependency is honored.

   Finally, the Standards Committee will eliminate any duplicate projects that appear in more than one program. The Standards Committee shall make the determination regarding in which program a project should reside. As these duplicate projects are eliminated, other projects may return or be added to the program.

   Additionally, the Prioritization will develop a list of potential projects for further research and planning. This list of potential projects will be brought to the Standing Committees for their assistance such that they may be considered in the following year for initiation.

7. **Adding New Projects Intra-year and Adjusting Project Priority**

When a new project emerges and is evaluated outside the annual prioritization, the resulting point scores may indicate that the new project should have priorities higher than other projects currently under active development. It is generally assumed that ongoing projects should have highest priority and should continue development work regardless of other projects' emergence. However, both emerging reliability issues and regulatory directives may lead the Standards Committee to direct that one or more projects that are currently assigned to a program be put on hold until resources become available and development work can be restarted.

The Standards Committee will decide if any of the ongoing projects should be stopped or deferred and advise the respective Standard Drafting Teams (SDTs) accordingly, or develop other remedial actions to launch the new projects and continue with all ongoing projects. If it determines that none of the ongoing projects should be stopped and the new projects should be launched, but no resource relief can be provided, the Standards Committee will bring the situation, along with options and recommendations, to the Board of Trustees for its attention and direction.

8. **Developing Projects Schedules**

The time required to complete a standard development project varies from one project to another depending on the scope of work and the complexity of the issues to be addressed. While the SAR proponents generally have a good grasp of the time required to complete a standard project from the formation of the SDT to balloting, the SDT itself may have more intimate knowledge of the technical issues involved and hence a better feel of the time needed to complete its assigned project. Further, since SDT members are industry volunteers that are committed to their projects, it is desirable and appropriate that the SDTs provide inputs into their project schedules and milestone events.

In general, NERC staff together with the Standards Committee will develop an initial project schedule based on past experience, complexity of the standards and other considerations such as available expertise, compliance deadlines, etc. Then, the SDT will be given the opportunity to review and adjust the project schedule at its initial meetings, and present a revised schedule, if necessary, to the Standards Committee for consideration. Once approved by the Standards Committee, the SDT will take ownership of the project and its schedule, and monitor and report project progress to the Standards Committee on an as-needed basis.

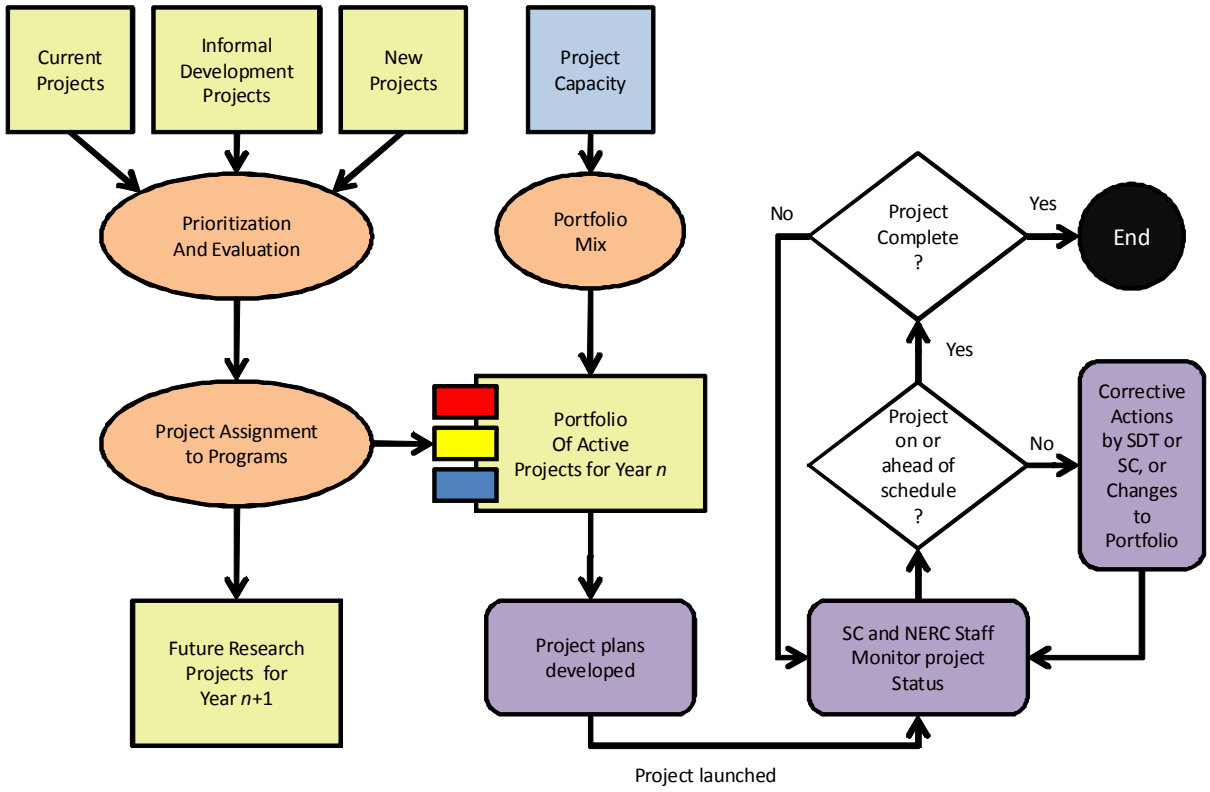
9. **Monitoring Projects**

The SDTs are responsible for monitoring all milestone events and completion schedules for their assigned projects. If at any time the milestone dates for a project are expected to be missed, the responsible SDT should report to the Standards Committee, and present options to put the project back on schedule or request accepting delays with supporting rationale. Where necessary, the SDT may seek the Standards Committee's endorsement or advice for other remedial actions including additional resource support, resolution of contentious issues, accepting an extension of the project schedule, or other actions deemed appropriate.

Such reporting should be made at least two months prior to a milestone date in danger of being missed, and at least four months prior to the scheduled completion date (end of re-circulation balloting) that is in danger of being missed. The Standards Committee will act upon receiving a report from the SDT of potential slippage. In its deliberation, it will assess impacts of implementing any remedial actions on the status of other ongoing or pending projects.

From time to time, the Standards Committee may request the Chair or a representative of an SDT to report on the progress of a project even though there is no indication of a potential slippage.

10. **Project Identification, Prioritization and Management Flow Diagram**
A flow diagram showing the process described in 1 to 9 is shown below.



Attachment A – Project Prioritization Tool Details

Below is a detailed description of the values and calculations used in the Project Prioritization Tool.

Rows

Row 1 Contains general information and macro buttons.

The ***"Sort"*** macro buttons simply sorts rows 3 through 250 in descending order of the associated column and re-establishes the rankings listed in columns B, T, U, V, W, and X as appropriate.

The ***Click Here to Insert a Row*** macro button shifts all existing data down one row to insert a blank row in row 3. Data will then need to be entered into the new row.

Row 2 Contains the column headers.

Columns

Column A Blank.

Column B ***Priority Number:*** The relative ranking or each project as a result of the most recent "Total" Sort performed.

Column C ***Project Number and Name***

Column D ***Short Description*** (of the Project)

Column E ***Addresses an ERO Strategic Priority***. If the project is expected to aid in meeting one of the ERO's identified strategic priorities, then 50 points are added to the project reliability score. This value is assigned by NERC staff, and is used to calculate the **Reliability Score.**

Column F ***Addresses a reliability risk not covered by an existing standard.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. In general, this value is intended to capture "gaps" in the reliability standards, and should consider factors such as how the project relates to instability, separation, or a cascading sequence of failures; how it relates to an adequate level of reliability; and how wide the impact of the project is. A "*Fill-in-the-blank"* standard would be one possible example of a "gap." This value is used to calculate the **Reliability Score.** It is also used with Columns G, H, and I in the calculation used to determine the **Cost Consideration Score.**

100 = Severe risk

75 = High risk

50 = Moderate risk

25 = Low risk

0 = N/A

Column G ***Improves one or more existing standards.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. In general, this value is intended to capture ways of improving the effectiveness of existing standards to provide improved reliability, such as raising the minimum level of compliance or adding additional requirements. This value is used to calculate the **Reliability Score.** It is also used with Columns F, H, and I in the calculation used to determine the **Cost Consideration Score.** The project is expected to improve reliability:

100 = Significantly

75 = Moderately

50 = Incrementally

25 = Minimally

0 = N/A

Column H ***Cost of Implementation.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. This value is used with Columns F, G, and I in the calculation of the **Cost Consideration Score,** and should consider such items as equipment purchases or upgrades, training, and similar costs. In other words, what would it cost the industry to become compliant with the standard? When considered in aggregate, the cost of complying with the standard is expected to be:

100 = Very high

75 = High

50 = Average

25 = Low

0 = Very Low

Column I ***Cost of Administration.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. This value is used with Columns F, G, and H in the calculation of the **Cost Consideration Score,** and should consider things such as the cost to retain data, the cost to document, and the cost of compliance staff evaluating data. In other words, what would it cost the industry (including applicable entities, regions, and NERC) to prove that the standard is being complied with? When considered in aggregate, the cost to demonstrate and verify compliance is expected to be:

100 = Very high

75 = High

50 = Average

25 = Low

0 = Very Low

Column J ***Time Sensitivity.*** Number of months until due date, if any, from the time the prioritization is effective. For example, in 2012, this should be the number of months from January 2012 to the due date. This value is assigned by NERC staff, and is used to calculate the **Time Sensitivity Score.** 0 indicates no deadline exists within the subsequent 60 months.

Column K ***Addresses compliance issues from NERC Staff or Stakeholders.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. For example, if Compliance had idenfied a frequently violated standard, or standards for which one or more CAN's had been developed, or standard which has been identified by stakeholders as being difficult to comprehend. This value is used to calculate the **Practicality Score.**

50 =Significant issues

25 = Moderate issues

10 = Minimal issues

0 = N/A

Column L ***Addresses a failed interpretation or SDT inability to develop an interpretation.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. This value is used to calculate the **Practicality Score.** The interpretation is needed to address a lack of clarity that is:

50 = Significant

25 = Moderate

10 = Minimal

0 = N/A

Column M ***Other Practicality Concern.*** This value is subjective in nature, and will be determined based on the consensus of the Standards Committee. An example of a project that would have points assigned here is the Vegetation Management project because of it being used at the prototype results based standard. Additional considerations would be the breadth of impact to registered entities, projects with active field trials, the length of time project has been in the queue, and projects that clarify a standard or delete redundant requirements. Addressing "*Fill-in-the-blank"* standard would be another area where practicality might drive a need to develop a standard by eliminating the potential for duplicate work among the regions. Between 0 and 50. This value is used to calculate the **Practicality Score**, and must be accompanied by an explanation of the relative value provided in Column N.

Column N ***Explanation:*** the explanation of the value set in column M.

Column O ***Reliability Score.*** The sum of columns E, F, and G. Between 0 and 250.

Column P ***Cost Consideration Score.*** Calculated based on the sum of columns F and G less the sum of the columns H and I, then scaled to produce a value between 0 and 100. Projects with no reliability benefit are automatically scored as 0.

Column Q ***Time Sensitivity Score.*** Calculated by dividing the number of months in column J by sixty, subtracting that value from one, and then multiplying by 100 and rounding. If the number of months is zero or greater than 60, then the score is set at 0. This results in projects with a closer deadline having a higher priority.

Column R ***Practicality Score.*** The sum of columns K, L, and M. Between 0 and 150.

Column S ***Total Score.*** The sum of the **Reliability Score, Cost Consideration Score, Time Sensitivity Score,** and **Practicality Score.** Based on total scores, results in a weighted score with approximately the following distribution of weights:

Reliability 41.6%
Cost Consideration 16.7%
Time Sensitivity 16.7%
Practicality 25%

Columns T-X ***Rankings.*** The numbers show the rankings for each area, and color codes the cells based on the following:

- The top *n* projects, where *n* is the number at the top of the column for columns U, W, and X
- All projects with a Cost Consideration Score greater than or equal to *n*, where *n* is the number at the top of column V.

Attachment B: Prioritization Tool

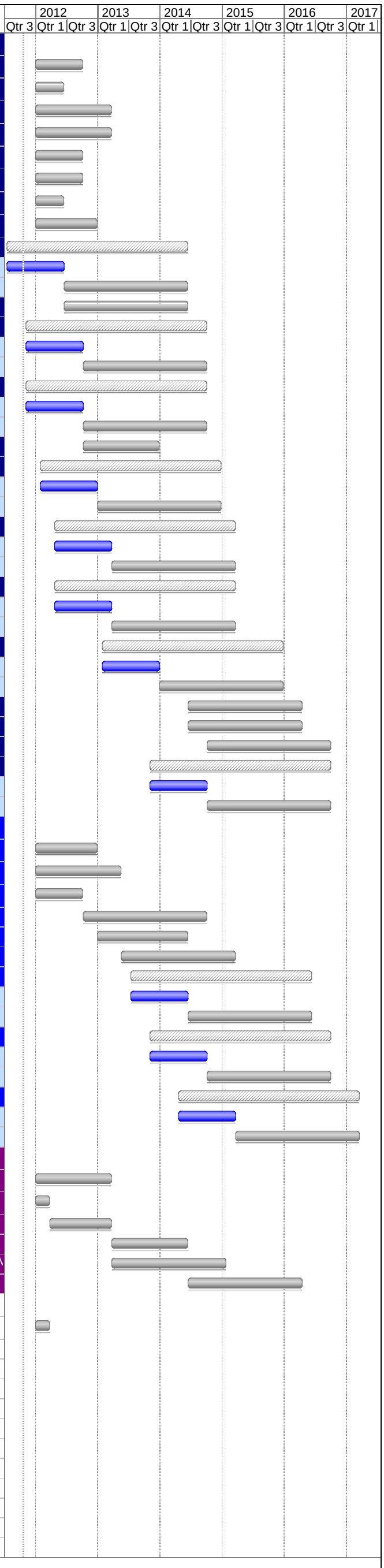
STANDARDS COMMITTEE Reliability Standard Project Prioritization			(E) Click Here to Insert a Row	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	SUMMARY						7	25	3	3
									Cells with this color are blank and need a value entered.				Sort	Sort	Sort	Sort	Sort					
TOTAL RANKING	Project Number and Name	Short Description	Addresses an ERO Strategic Priority (to be completed by NERC Staff) 50 = Yes 0 = No	Addresses a reliability risk not covered by an existing standard 100 = Severe risk 75 = High risk 50 = Moderate risk 25 = Low risk 0 = N/A	Improves one or more existing standards: 100 = Significantly 75 = Moderately 50 = Incrementally 25 = Minimally 0 = N/A	Cost of Implementation The cost of complying with the standard is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	Cost of Administration The cost to demonstrate and verify compliance is expected to be: 100 = Very high 75 = High 50 = Average 25 = Low 0 = Very Low	Time Sensitivity (to be competed by NERC Staff) Number of months until due date, if any	Addresses compliance issues from NERC Staff or Stakeholders 50 =Significant issues 25 = Moderate issues 10 = Minimal issues 0 = N/A	Addresses a failed interpretation or SDT inability to develop an interpretation related to a lack of clarity that is 50 = Significant 25 = Moderate 10 = Minimal 0 = N/A	Other Practicality Concern (Explanation for the rating must be indicated in the column to the right) (0 to 50)	Explanation	Reliability Score (0 - 250)	Cost Consideration Score (0 - 100)	Time Sensitivity Score (0 - 100)	Practicality Score (0 - 150)	Total Score (0-600)	TOTAL RANKING	Relaibity Ranking	Cost Consideration Ranking	Time Sensitivity Ranking	Practicality Rnaking
1	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Draft new standard PRC-025-1 Generator Relay Loadability in compliance with the FERC Order 733 issued March 18, 2010											0	0	0	0	0	1	1	1	1	1
2	Project 2010-13-3 Phase 3 of Relay Loadability: Stable Power Swings												0	0	0	0	0	2	2	2	2	2
3	Project 2010.05.2 Phase 2 of Protections Systems: SPS and RAS	Modify current PRC-012, -014, and -016 standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. May include additional udpates to PRC-004 as well.											0	0	0	0	0	3	3	3	3	3
4	Project 2010-16 Definition of System Operator												0	0	0	0	0	4	4	4	4	4
5	Project 2007-17 Protection System Maintenance & Testing	Transmission and Generation Protection System Maintenance and Testing, to consolidate PRC-005-1, PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs; PRC-011-0 — UVLS System Maintenance and Testing; and PRC-017-0 — Special Protection System Maintenance and Testing into a single maintenance and testing standard. Standards PRC-008-0, PRC-011-0, and PRC-017-0 would then be withdrawn.											0	0	0	0	0	5	5	5	5	5
6	Project 2007-06 System Protection Coordination	Requires upgrading and expanding the existing requirements to identify criteria for determining where to install protection system devices and for requiring the installation of those devices to protect the reliability of the bulk electric system.											0	0	0	0	0	6	6	6	6	6
7	Project 2007-12 Frequency Response	Requires entities to provide data needed to model each interconnection's frequency response.											0	0	0	0	0	7	7	7	7	7
8	Project 2010-05.1 Phase 1 of Protection Systems: Misoperations	Modify current PRC-003 and -004 standards and definitions related to Protection System Misoperations to support a good metric for measurement of Protection System performance and ensure the reliability of the bulk power system. Does not incude SPS and RAS.											0	0	0	0	0	8	8	8	8	8
9	Project 2008-06 Cyber Security - Order 706	This is the second phase (Phase 2) of Project 2008-06 Cyber Security Order 706. The project requires modifications to CIP-002 thru CIP-009 not included in Phase 1 of the project to bring the standards into conformance with the ERO Rules of Procedure and to address the directives from FERC Order 706.											0	0	0	0	0	9	9	9	9	9
10	Project 2010-07 Transmission Requirements at the Generator Interface	This project proposes changes to the requirements and the addition of new requirements to add significant clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid.											0	0	0	0	0	10	10	10	10	10
11	Project 2009-01 Disturbance and Sabotage Reporting	This project will entail revision to existing standards CIP-001 and EOP-004. The standards may be merged to eliminate redundancy and provide clarity on sabotage events. EOP-004 has some 'fill-in-the-blank' components to eliminate. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.											0	0	0	0	0	11	11	11	11	11

Appendix 2 – Work Plan

The following page shows the schedule of work in Gantt chart format. Projects for which the Standing Committees will be asked to provide research are identified with blue Gantt chart bars, and have been tentatively allocated a year duration for research (pending feedback from the Standing Committees).

Following the Prioritization, the Work Plan is the next step in the creation of the Reliability Standards Development Plan. It is used primarily to identify project predecessors and ensure resource allocations are consistent and manageable. Once complete, it identifies the estimated start and completion of all projects over the three-year period.

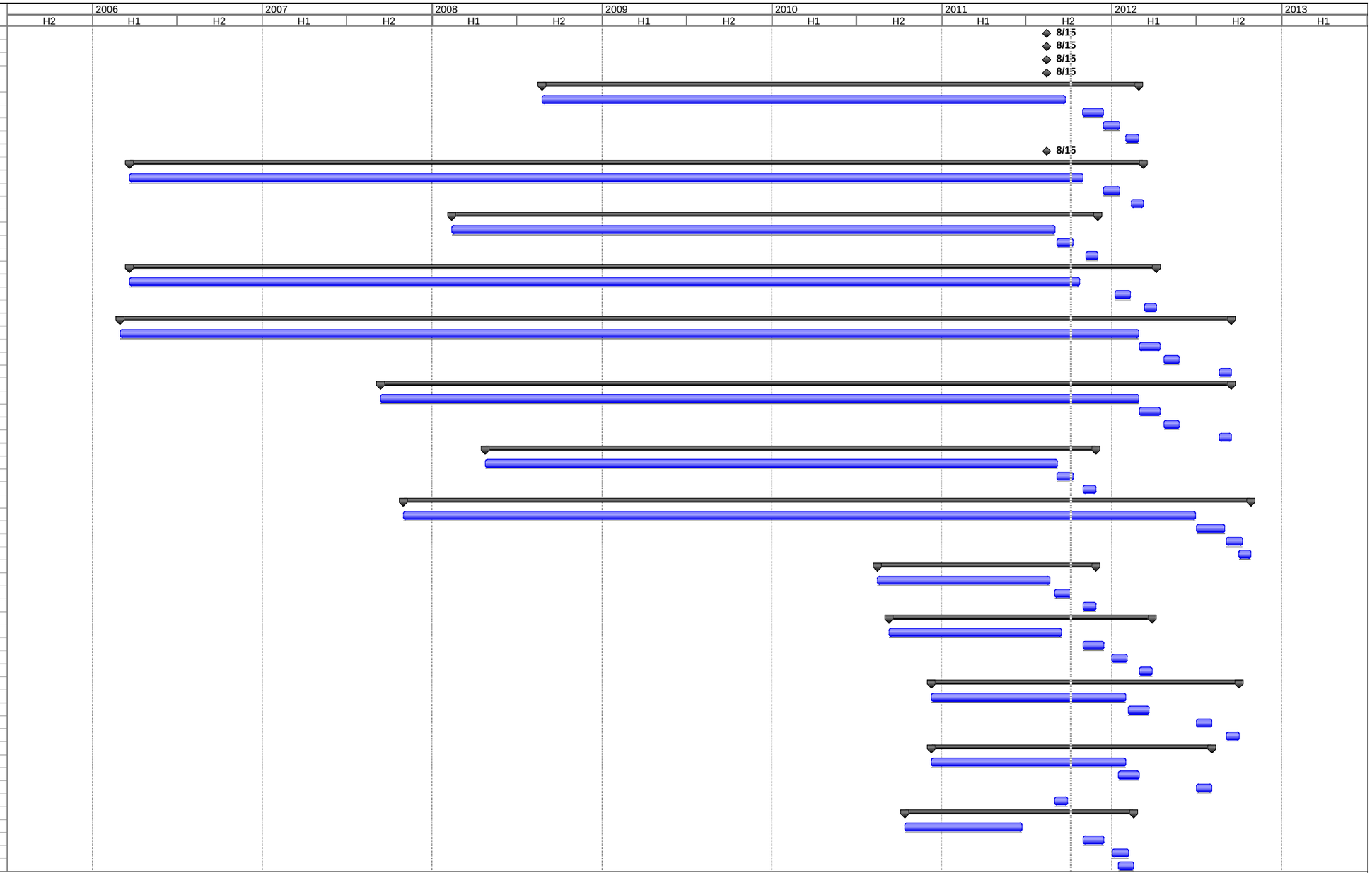
ID	Task Name
1	**Reliability Projects: 8 Slots**
2	**Project 2008-06 Cyber Security - Order 706 (ACTIVE)**
3	**Project 2007-17 Protection System Maintenance & Testing (ACTIVE)**
4	**Project 2007-02 Operating Personnel Communications Protocols (ACTIVE)**
5	**Project 2007-06 System Protection Coordination (ACTIVE)**
6	**Project 2009-01 Disturbance and Sabotage Reporting (ACTIVE)**
7	**Project 2010-05.1 Phase 1 of Protection Systems: Misoperations (ACTIVE)**
8	**Project 2006-06 Reliability Coordination (ACTIVE)**
9	**Project 2007-09 Generator Verification (ACTIVE)**
10	***Project 2012-04 Protection System Commissioning Testing***
11	Standing Committee Research
12	Standards Development
13	Project 2008-02 Undervoltage Load Shedding
14	**Project 2010-05.2 Phase 2 of Protections Systems: SPS and RAS**
15	Standing Committee Research
16	Standards Development
17	**Project 2010-01 Support Personnel Training**
18	Standing Committee Research
19	Standards Development
20	Project 2009-03 Emergency Operations (INFORMAL)
21	**Project 2012-06 Generator Capabilities**
22	Standing Committee Research
23	Standards Development
24	**Project 2009-07 Reliability of Protection Systems**
25	Standing Committee Research
26	Standards Development
27	**Project 2012-01 Equipment Monitoring and Diagnostic Devices**
28	Standing Committee Research
29	Standards Development
30	**Project 2009-04 Phasor Measurements**
31	Standing Committee Research
32	Standards Development
33	Project 2009-05 Resource Adequacy Assessments
34	Project 2010-16 Definition of System Operator
35	Project 2010-08 Functional Model Glossary Revisions
36	**Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings**
37	Standing Committee Research
38	Standards Development
39	**Time-Sensitive Projects - 3 Slots**
40	**Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Control: Reserves (ACTIVE)**
41	**Project 2010-17 Definition of BES (ACTIVE)**
42	**Project 2007-12 Frequency Response (ACTIVE)**
43	Project 2010-13.2 Phase 2 of Relay Loadability: Generation (INFORMAL)
44	Project 2008-01 Voltage and Reactive Planning and Control (INFORMAL)
45	Project 2007-11 Disturbance Monitoring (INFORMAL)
46	**Project 2010-03 Modeling Data**
47	Standing Committee Research
48	Standards Development
49	**Project 2010-04 Demand Data**
50	Standing Committee Research
51	Standards Development
52	**Project 2010-02 Connecting New Facilities to the Grid**
53	Standing Committee Research
54	Standards Development
55	**Practicality Projects - 2 Slots**
56	**Project 2010-07 Generator Requirements at the Transmission Interface (ACTIVE)**
57	**Project 2007-03 Real-time Transmission Operations (ACTIVE)**
58	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities (INFORMAL)
59	Project 2008-12 Coordinate Interchange Standards (INFORMAL)
60	Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent (INFORM
61	Project 2012-05 ATC-Revisions - Order 729
62	**Excess Beyond Capacity for 2012-2014**
63	**Project 2007-07 Vegetation Management (ACTIVE)**
64	Project 2012-02 Physical Protection
65	Project 2012-03 PRC-004 VSLs
66	Project 2012-08 Glossary Updates
67	Project 2012-07 Obsolescence Review
68	Project 2012-09 IRO Review
69	Project 2012-11 FAC Review
70	Project 2012-12 PER Review
71	Project 2012-13 NUC Review
72	Project 2012-14 Risk Analysis
73	*2006-06.2 Phase 2 of Reliability Coordination*
74	*2012-15 Flow Limited Paths*



Appendix 3 – Regional Work Plan

The following page shows the schedule of regional work in Gantt chart format. Projects that are actively being pursued are identified with black Gantt chart bars, with blue bars representing various stages of development. Projects that are "on hold" are represented by a black diamond.

ID	Task Name
1	**PRC-002-FRCC-1 (on hold)**
2	**PRC-003-FRCC-1 (on hold)**
3	**PRC-006-FRCC-1 (on hold)**
4	**PRC-024-FRCC-1 (on hold)**
5	**PRC-006-NPCC-1**
6	Regional standard development
7	Posting of Documents for process evaluation at NERC
8	Prepare BOT Material
9	Develop Initial Draft of Regulatory Filings
10	**PRC-012-NPCC-1 (on hold)**
11	**MOD-024-RFC-01**
12	Regional standard development
13	Prepare BOT Material
14	Develop Initial Draft of Regulatory Filings
15	**MOD-025-RFC-01**
16	Regional standard development
17	Prepare BOT Material
18	Develop Initial Draft of Regulatory Filings
19	**PRC-002-RFC-01**
20	Regional standard development
21	Prepare BOT Material
22	Develop Initial Draft of Regulatory Filings
23	**PRC-006-RFC-1**
24	Regional standard development
25	Posting of Documents for process evaluation at NERC
26	Prepare BOT Material
27	Develop Initial Draft of Regulatory Filings
28	**PRC-012-RFC-1**
29	Regional standard development
30	Posting of Documents for process evaluation at NERC
31	Prepare BOT Material
32	Develop Initial Draft of Regulatory Filings
33	**PRC-006-SERC-01**
34	Regional standard development
35	Prepare BOT Material
36	Develop Initial Draft of Regulatory Filings
37	**PRC-006-SPP-01**
38	Regional standard development
39	Posting of Documents for process evaluation at NERC
40	Prepare BOT Material
41	Develop Initial Draft of Regulatory Filings
42	**IRO-006-TRE-1**
43	Regional standard development
44	Prepare BOT Material
45	Develop Initial Draft of Regulatory Filings
46	**BAL-001-TRE-1**
47	Regional standard development
48	Posting of Documents for process evaluation at NERC
49	Prepare BOT Material
50	Develop Initial Draft of Regulatory Filings
51	**BAL-002-WECC-1**
52	Regional standard development
53	Posting of Documents for process evaluation at NERC
54	Prepare BOT Material
55	Develop Initial Draft of Regulatory Filings
56	**BAL-004-WECC-1**
57	Regional standard development
58	Posting of Documents for process evaluation at NERC
59	Prepare BOT Material
60	Develop Initial Draft of Regulatory Filings
61	**VAR-001-WECC-1**
62	Regional standard development
63	Posting of Documents for process evaluation at NERC
64	Prepare BOT Material
65	Develop Initial Draft of Regulatory Filings



Project: Unified Regional Project Sche
Date: Wed 10/5/11

Task | Progress | Summary | External Tasks | Deadline
Split | Milestone | Project Summary | External Milestone

Appendix 4 – Project Summaries

The following are detailed summaries of the projects discussed earlier within this plan.

DEVELOPMENT 2012

Project 2006-06 Reliability Coordination

Summary:

This project ensures that the reliability-related requirements applicable to the Reliability Coordinator are clear, measurable, unique, and enforceable, and that this set of requirements is sufficient to maintain reliability of the Bulk Electric System. Most of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process. There have been suggestions for improving these requirements, and the drafting team is considering comments submitted by stakeholders, drafting teams and FERC in determining what changes should be proposed. The drafting team is reviewing all of the requirements in this set of standards and making a determination whether to:

- Modify the requirement to improve clarity and measurability while removing ambiguity;
- Move the requirement (into another project or Standard, or to the certification process); or
- Eliminate the requirement (because it is redundant or does not support BPS reliability).

This project ranked #13 in Reliability Priority.

Standards affected:

COM-001, COM-002, IRO-001- IRO-002, IRO-005, IRO-014, IRO-015, IRO-016

Status:

This project's SAR was finalized on May 2, 2007. The draft standards have been posted several times. The NERC Board of Trustees adopted IRO-002-3, IRO-005-4 and IRO-014-2, along with a conforming change to IRO-001-1.1 associated with IRO-014-2 (creating IRO-001-2) on August 4, 2011. The Board also approved the retirement of IRO-015-1 and IRO-016-1. The drafting team is continuing development on COM-001-2, COM-002-3, and additional revisions to IRO-001, which will become IRO-001-3. It is estimated this project will complete in Q2 2012.

FUTURE CONSIDERATION

Project 2006.06.2 Phase 2 of Reliability Coordination: IRO-003

Summary:

This project will address directives from Order 693 related to the inclusion of measures in IRO-003 and the determination of "critical facilities."

Standards affected:

IRO-003

Status:

A SAR was developed and was finalized on July 14, 2010. However, no additional work has occurred for this project at this time. No estimate for starting the project has been identified.

DEVELOPMENT 2012

Project 2007-02 Operating Personnel Communication Protocols

Summary:

This project is reviewing COM-003 to ensure the standard is complete, appropriately scoped, and enforceable. The project is also considering other general improvements and stakeholder comments received during the initial development of the standards, as well as other comments received from Electric Reliability Organization (ERO) regulatory authorities. This also satisfies the NERC requirement for five-year review of the standard.

This standard will require the use of specific communication protocols, especially for communications during alerts and emergencies. The standard will be applicable to transmission operators, balancing authorities, reliability coordinators, generator operators and distribution providers. Requirements will include protocols for communicating changes to real-time operating states and protocols for issuing and responding to operating directives.

This project ranked #5 in Reliability Priority.

Standards affected:

COM-003

Status:

This project's SAR was finalized on June 8, 2007. A draft standard was posted November 20, 2009 through January 15, 2010. Due to focusing on other priorities, this team was temporarily put on hold. The project was restarted in 2011, and the team is reviewing comments and preparing to post a new version of the standard. It is estimated this project will complete in Q1 2013.

DEVELOPMENT 2012

Project 2007-03 Real-time Transmission Operations

Summary:

This project is clarifying requirements for real-time operations of the Bulk Electric System in several standards, as well as providing other general improvements. It will consider stakeholder comments received during the initial development of the standards, as well as other comments received from ERO regulatory authorities. This also satisfies the NERC requirement for five-year review of the standards.

This project ranked #5 in Practicality Priority.

Standards affected:

PER-001, TOP-001, TOP-002, TOP-003, TOP-004, TOP-004, TOP-005¸ TOP-006, TOP-007, TOP-008

Status:

This project's SAR was finalized November 1, 2007. The standards have been posted several times for public comment. The standards were posted most recently for Initial Ballot from May 31, 2011 through June 9, 2011. It is estimated this project will complete in Q1 2012.

DEVELOPMENT 2012

Project 2007-06 System Protection Coordination

Summary:

This project is reviewing PRC-001-1 to assure that Protection System application and performance issues are coordinated among all related entities. It will ensure the applicable entities within the standard correctly reflect the functional responsibilities, as described in the NERC Functional Model. The project will also incorporate other general improvements, address directives received from ERO regulatory authorities, and consider the observations and recommendations developed by the NERC SPCTF. As necessary, the project will coordinate the transfer of monitoring-related requirements to other standards as appropriate through coordination with project 2006-06 Reliability Coordination.

This project ranked #4 in Reliability Priority.

Standards affected:

PRC-001, PRC-027 (New)

Status:

This project's SAR was finalized on July 27, 2007. A draft standard was posted from September 9, 2009 through October 26, 2009. Several interim drafts have been developed since that time. A new results-based version of the standard is in development. It is estimated this project will complete in Q1 2013.

DEVELOPMENT 2012

Project 2007-07 Vegetation Management

Summary:

This project will address some 'fill-in-the-blank' components of the existing standard, which were created in 2006 (prior to mandatory and enforceable standards). The project also will investigate applicability to lower voltage transmission lines, address the issue of clearances for lines on both federal and non-federal lands, consider revising the definition of right of way to encompass required clearance areas, and review the suitability of the IEEE 516-2003 standard for minimum vegetation clearance. This also satisfies the NERC requirement for five-year review of the standard.

Standards affected:

FAC-003

Status:

This project's SAR was finalized June 27, 2007. The standards have been posted several times for public comment. The standards were most recently posted for Successive Ballot from February 18, 2011 through February 28, 2011. The team has drafted a revised standard and has requested it be posted for Recirculation Ballot. It is estimated this project will complete in Q1 2012.

DEVELOPMENT 2012

Project 2007-09 Generator Verification

Summary:

This project will create or modify standards to ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions. It also will ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

Standards affected:

MOD-024, MOD-025, MOD-026, MOD-027, PRC-019, PRC-024

Status:

This project's SAR was finalized June 14, 2007. The standards have been posted several times for public comment. Two of the standards were posted most recently for Initial Ballot from July 22, 2011 through August 1, 2011. Three other standards were posted for comment June 12, 2011 through July 15, 2011. It is estimated this project will complete in Q4 2012.

PENDING 2013

Project 2007-11 Disturbance Monitoring

Summary:

Purpose
This project establishes and clarifies requirements for the installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. The project will review PRC-002 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to or contained within the disturbance monitoring program documentation. The project will then determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

Standards affected:

PRC-002, PRC-018

Status:

This project's SAR was finalized May 21, 2007. An initial draft standard was posted from February 2, 2009, to March 18, 2009. This project was moved to informal development in 2011. It is estimated this project will start in Q2 2013 and complete in Q1 2015.

DEVELOPMENT 2012

Project 2007-12 Frequency Response

Summary:

Purpose:
This project will modify the BAL-003 Standard to require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds. It also will ensure the standard provides consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

This project is one of several that share the #2 score for Time Sensitivity Priority.

Standards affected:

BAL-003

Status:

This project's SAR was finalized June 30, 2007. The standard has been posted once for public comment, and is expected to be posted for comment in Q4 of 2011. The project is expected to complete in Q2, 2012.

DEVELOPMENT 2012

Project 2007-17 Protection System Maintenance and Testing

Summary:

This project will modify the standards related to ensuring all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested. The project will respond to various FERC directives contained in Order 693, as well as make general improvements to the standard.

This project ranked #3 in Reliability Priority.

Standards affected:

PRC-005, PRC-008, PRC-011, PRC-017

Status:

This project's SAR was finalized May 7, 2007. The standards have been posted several times for public comment. The standards were posted most recently for Initial Ballot from September 19, 2011 through September 28, 2011. It is estimated this project will complete in Q2 2012.

PENDING 2013

Project 2008-01 Voltage and Reactive Planning and Control

Summary:

This project will revise the VAR Standards to require that appropriate functional entities develop and coordinate voltage and reactive planning and operating criteria to ensure that there are sufficient reactive resources, and voltage and reactive margins, to manage the risk of voltage instability. The project will also address the FERC directives in Order 693 associated with these standards. Review and modifications to the existing VAR standards will also consider the Transmission Issues Subcommittee's "Reactive Support & Control Whitepaper" dated 05/18/2009.

This project ranked #3 in practicality.

Standards affected:

VAR-001, VAR-002

Status:

This project's SAR was finalized April of 2011. This project was moved into informal development in 2011, prior to posting any daft of the standard. It is estimated this project will begin in Q1 2013 and complete in Q2 2014.

PENDING 2012

Project 2008-02 Undervoltage Load Shedding

Summary:

This project will improve the existing standards on Under Voltage Load Shedding (UVLS) to ensure that load is shed when needed to prevent voltage collapse and voltage instability in the Bulk Electric System. The existing standards will be consolidated, and specific criteria for UVLS programs and assessments of those UVLS programs should be added. 'Fill-in-the-blank' elements should be eliminated, and concerns related to Fault-Induced Delayed Voltage Recovery will be reviewed and addressed.

This project ranked #14 in Reliability Priority.

Standards affected:

PRC-010, PRC-022

Status:

This standard has a proposed SAR that was posted for comment from January 20, 2010, through February 19, 2010. It is estimated this project will start in Q3 2012 and complete in Q2 2014.

DEVELOPMENT 2012

Project 2008-06 Cyber Security – Order 706

Summary:

This project establishes standards to protect the critical cyber assets (including hardware, software, data, and communications networks) essential to the reliable operations of the bulk power system. Currently the project is focused on Version 5 of the standards, which is focused on addressing the remaining directives in Order 706.

This project ranked #2 in Reliability Priority.

Standards affected:

CIP-002, CIP-003, CIP-004, CIP-005, CIP-006, CIP-007, CIP-008, CIP-009, CIP-010 (New), CIP-011 (New)

Status:

This project's SAR was finalized June 9, 2008. Older versions of the standard have been posted, balloted, and approved several times. Version 5 of the standards has not yet been posted for comment. It is estimated this project will complete in Q3 2012.

PENDING 2013

Project 2008-12 Coordinate Interchange Standards

Summary:

This project will revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator, or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-ties; and to address previously identified stakeholder comments. The project also will consider adding requirements to have backup capability for use when the interchange transaction tool fails.

Standards affected:

INT-001, INT-003, INT-004, INT-005, INT-006, INT-007, INT-008, INT-009, INT-010

Status:

This project's SAR was finalized December 1, 2008. An initial draft set of standards was developed and posted for comment from November 10, 2009 through December 9, 2009. However, the project was moved into informal development in 2011. It is estimated this project will start in Q2 2013 and complete in Q2 2014.

DEVELOPMENT 2012

Project 2009-01 Disturbance and Sabotage Reporting

Summary:

Purpose:

This project entails revisions to existing standards CIP-001-1 – Sabotage Reporting and EOP-004-1 – Disturbance Reporting. The project will eliminate redundancy and provide clarity on sabotage events. Additionally, EOP-004 will be reviewed to eliminate any 'fill-in-the-blank' components.

This project ranked #8 in Reliability Priority.

Standards affected:

CIP-001, EOP-004

Status:

This project's SAR was finalized August 13, 2009. The standard has been posted for comment twice, and is being prepared for Initial Ballot. It is estimated this project will complete in Q3 2012.

PENDING 2012

Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities

Summary:

This project will create new or revised standards to establish requirements for the monitoring and analysis capabilities provided to System Operators to support Real-time System Operations. The project will address availability parameters, performance metrics, and procedures for failure notification, maintenance coordination, and change management.

This project ranked #1 in Practicality Priority.

Standards affected:

New

Status:

This project's SAR was finalized March 31, 2010. The project team posted a White Paper created to illustrate the concepts it intends to pursue as the project unfolds. This posting solicited comments from February 16, 2011, through April 4, 2011. This project was moved to informal development in 2011. It is estimated this project will start in Q2 2012 and complete in Q1 2013.

PENDING 2012

Project 2009-03 Emergency Operations

Summary:

This project will review the EOP-001, EOP-002, and EOP-003 standards and associated interpretations to ensure the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process; suggestions for improvement have been submitted by stakeholders, other drafting teams, and FERC staff.

This project ranked #4 in Practicality Priority.

Standards affected:

EOP-001, EOP-002, EOP-003

Status:

This project's SAR was finalized November 5, 2010. Prior to the development of an initial draft standard, this project was moved to informal development. It is estimated this project will start in Q3 2012 and complete in Q4 2013.

2014 PENDING RESEARCH

Project 2009-04 Phasor Measurements

Summary:

This project will review several industry studies to determine if there should be phasor requirements developed for a NERC standard. This project is related to the North-American Synchro-Phasor Initiative, and supports a blackout recommendation.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q1 2014 and complete in Q4 2015.

PENDING 2014

Project 2009-05 Resource Adequacy Assessments

Summary:

This project will implement certain recommendations related to resource adequacy from the *Resource and Transmission Adequacy Task Force (RTATF) Report* and the *Gas/Electricity Interdependency Task Force Report,* approved by the NERC Board on June 15, 2004. The project will create a standard with requirements to perform resource adequacy assessments, using metrics that take into account various factors (including, but not limited to, fuel deliverability). The standard would also make the results of the assessments available to the industry, NERC, and appropriate regulatory agencies.

Standards affected:

New

Status:

This project's SAR was finalized August 17. 2007. Prior to the development of an initial draft standard, this project was moved to informal development in 2011. It is estimated this project will start in Q3 2014 and complete in Q2 2016.

2013 PENDING RESEARCH

Project 2009-07 Reliability of Protection Systems

Summary:

This project will ensure Protection Systems are designed and installed with redundancy where appropriate, such that if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards.

This project ranked #1 in Reliability Priority.

Standards affected:

New

Status:

This project has an initial draft of a SAR that was posted for comment January 20, 2009, through February 18, 2009. Comment responses have not been prepared, and the SAR has not been finalized. It is estimated this project will start in Q1 2013 and complete in Q1 2015.

2012 PENDING RESEARCH

Project 2010-01 Support Personnel Training

Summary:

This project will develop a standard that requires the use of a systematic approach to determining training needs of generator operators and operations planning and support staff with a direct impact on the reliable operations of the bulk power system.

This project ranked #15 in Reliability Priority.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q3 2012 and complete in Q3 2014.

FUTURE CONSIDERATION, PENDING RESEARCH

Project 2010-02 Connecting New Facilities to the Grid

Summary:

22 - Ensure that all of the elements that should be addressed when a new facility is connected to the grid are included in the revised standard. FAC-001 and -002.

Standards affected:

FAC-001, FAC-002

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q2 2015 and complete in Q1 2017.

2014 PENDING RESEARCH

Project 2010-03 Modeling Data

Summary:

This project will consider merging, upgrading and expanding existing requirements for entities to provide data used to model the bulk electric system. This project is related the Modeling Initiative, and supports a blackout recommendation.

Standards affected:

MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, PRC-013, PRC-015

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q3 2014 and complete in Q2 2016.

2014 PENDING RESEARCH

Project 2010-04 Demand Data

Summary:

This project will consolidate MOD-016 through MOD-020 into a single standard, with MOD-021 remaining as a separate standard. Requirements will be made be more specific to clearly identify the format for providing data, and modifications will made in support if previously received industry comments and regulatory directives.

Standards affected:

MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, MOD-021

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q3 2014 and complete in Q3 2016.

DEVELOPMENT 2012

Project 2010-05.1 Phase 1 of Protection Systems: Misoperations

Summary:

This project addresses a key element for Bulk Electric System (BES) reliability: the correct performance of Protection Systems. Monitoring BES Protection System events to identify and correct the root causes of Misoperations will improve overall Protection System performance. The project will revise the definition of Misoperation and redraft the standard to be more clear and unambiguous.

This project ranked #7 in Reliability Priority.

Standards affected:

PRC-003, PRC-004

Status:

This project's SAR was finalized June 9, 2011. An initial draft of the standard was posted for comment from June 10, 2011 through July 11, 2011. A second draft is being prepared for posting and initial ballot. It is estimated this project will complete in Q3 2012.

2012 PENDING RESEARCH

Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS

Summary:

This project will moodily the current standards and definitions related to SPS/RAS Misoperations to support a good metric for measurement of Protection System performance and to ensure the reliability of the bulk power system. This project is related to the System Protection Initiative.

This project ranked #11 in Reliability Priority.

Standards affected:

PRC-012, PRC-014, PRC-016.

Status:

This project has a draft SAR, but it has not yet been posted for comment. It is estimated this project will start in Q4 2012 and complete in Q3 2014.

DEVELOPMENT 2012

Project 2010-07 Generator Requirements at the Transmission Interface

Summary:

This project will develop any needed changes to the Reliability Standards to provide clarity to Generator Owners and Generator Operators regarding their reliability standard obligations at the interface with the interconnected grid. The project will review standard for applicability, propose changes as necessary, and ensure that requirements that should apply to all generators, regardless of interconnection configuration, are implemented effectively.

This project ranked #12 in Reliability Priority, #13 in Practicality Priority, and is one of several that share the #2 score for Time Sensitivity Priority.

Standards affected:

FAC-001, FAC-003, PRC-004, others as needed

Status:

This project's SAR was finalized November 30, 2010. A draft set of standards was developed and posted from June 17, 2011 through July 17, 2011. Discussion and coordination between NERC, FERC , and the members of the project team are ongoing to ensure adequate coverage of all reliability needs. It is estimated this project will complete in Q1 2013.

FUTURE CONSIDERATION

Project 2010-08 Functional Glossary Model Revisions

Summary:

This project will ensure the definitions of various functional entities between the Functional Model, the NERC Glossary of Terms, and the NERC Statement of Compliance Registration Criteria are consistent.

Standards affected:

TBD

Status:

The Functional Model Working Group (FMWG) is responding to comments received from the first posting of the SAR. It is estimated this project will start in Q4 2014 and complete in Q3 2016.

PENDING 2012

Project 2010-13.2 Phase 2 of Relay Loadability: Generation

Summary:

This project is being created in response to directives included in FERC Order 733. The project will draft a new standard to address generator relay loadability.

Standards affected:

New

Status:

This project's SAR was finalized November 1, 2010. Prior to the development of an initial draft, this project was moved to informal development in 2011. It is estimated this project will start in Q4 2012 and complete in Q3 2014.

2014 PENDING RESEARCH

Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings

Summary:

This project is being created in response to directives includes in FERC Order 733. The project will draft a new standard to address protective relay operations due to power swings.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q4 2014 and complete in Q3 2016.

DEVELOPMENT 2012

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves

Summary:

This project will review the standard related to Control Performance and Disturbance control, and propose modifications or new standards as necessary. This project includes the testing and analysis of the new Balancing Authority ACE Limit (BAAL) metric, as well as the development of a continent-wide reserve policy to support BAL-01, BAL-002, and BAL-003.

This project ranked #1 in Time Sensitivity Priority, and #2 in Practicality Priority.

Standards affected:

BAL-001, BAL-002, New

Status:

This project was created by merging two existing teams. As such, there are two SARs associated with the project – one that was finalized on November 7, 2007, and one that was finalized on December 3, 2007. The combined effort was moved into informal development in 2011, but restarted to coordinate with project 2007-12 Frequency Response. It is estimated this project will complete in Q4 2012.

PENDING 2013

Project 2010-14.2 Project 2010-14.2 Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent

Summary:

This project will consider the Time Error Correction standard, AGC, standard, and Inadvertent Accounting standard to determine what changes, if any, are necessary to ensure the standards are clear and unambiguous. In some cases, the standard may no longer be necessary.

Standards affected:

BAL-004, BAL-005, BAL-006

Status:

This project is currently in informal development. Based on its priority, it has been identified in the 2012-2014 Work Plan to begin in Q2 2013 and complete in Q1 2015.

PENDING 2014

Project 2010-16 Definition of System Operator

Summary:

This project will remove the 'Generator Operator' from the current definition of System Operator. This will more accurately establish the responsibilities and expectations of the Generator Operator consistent with the current manner in which the bulk electric system is operated.

Standards affected:

TBD

Status:

A proposed SAR and revision to the definition of System Operator was posted for a 30-day formal comment period from November 3, 2010 through December 3, 2010. It is estimated this project will start in Q3 2014 and complete in Q1 2016.

DEVELOPMENT 2012

Project 2010-17 Definition of Bulk Electric System

Summary:

This project will revise the definition of Bulk Electric System (BES) to address various Federal Energy Regulatory Commissions (FERC) concerns the definition must be modified to encompass all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. These concerns have been identified in FERC Order 693 issued on March 16, 2007 and in Order 743 issued on November 18, 2010 (Order 743). The project will also consider additional modifications (beyond those established in the regulatory directives) to improve clarity, to reduce ambiguity and to establish consistency across all Regions in distinguishing between BES and non-BES Elements and Facilities.

This project ranked #10 in Reliability Priority, and is one of several that share the #2 score for Time Sensitivity Priority.

Standards affected:

Multiple

Status:

This project's SAR was finalized March 25, 2011. The draft definition has been posted twice, with the most recent posting done concurrently with an initial ballot from September 30, 2011, to October 02 2011. The first part of this project is expected to complete in Q1 of 2012. The remainder of this project is estimated to complete in Q2 2013.

2013 PENDING RESEARCH

Project 2012-01 Equipment Monitoring and Diagnostic Devices

Summary:

This project will consider the development of reliability standards for the application of major equipment monitoring and diagnostic devices and procedures, with the intent of identifying potential equipment failures prior to their occurrence. This will provide more time to address failing systems and avoid or minimize long lead times.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q2 2013 and complete in Q1 2015.

FUTURE CONSIDERATION

Project 2012-02 Physical Protection

Summary:

This project will develop standards for the safety and protection of essential equipment, buildings, and people located in power generation, transmission, or distribution system locations in order to mitigate the associated reliability risks to the bulk power system.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-03 PRC-004 VSLs

Summary:

This project will address a problem identified in the VSLs of PRC-004. Currently, the VSLs do not address the case where a Corrective Acton Plan was developed or documented, but not fully implemented.

Standards affected:

PRC-004

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

2012 PENDING RESEARCH

Project 2012-04 Protection System Commissioning Testing

Summary:

This project will address a gap in reliability related to protection systems by creating a standard that requires commissioning testing. Improper or inadequate commissioning testing practices are a common cause of protection system Misoperation. However, the current set of approved NERC reliability standards does not address the testing of protection system equipment *before* that equipment is placed into initial service. Creating a commissioning standard would also enhance the effectiveness of the mandatory auditing program.

This project ranked #9 in Reliability Priority,

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q2 2012 and complete in Q2 2014.

PENDING 2014

Project 2012-05 ATC Revisions - Order 729

Summary:

This project will respond to the remaining directives in Order 729.

Standards affected:

MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, MOD-030

Status:

This is a new project, which will require SAR development. It is estimated this project will start in Q3 2014 and complete in Q1 2016.

2013 PENDING RESEARCH

Project 2012-06 Generator Capabilities

Summary:

This project will develop standards to ensure generator performance. The project should consider requirements that specify governor droop, frequency response, and reactive response.

This project ranked #6 in Reliability Priority

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. It is estimated this project will start in Q1 2013 and complete in Q4 2014.

FUTURE CONSIDERATION

Project 2012-07 Obsolescence Review

Summary:

This project will create a standard that requires Generator and Transmission Owners periodically review their control and protection systems to identity and electronic, electrical, or mechanical devices that have become obsolete.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-08 Glossary Updates

Summary:

This project will respond to FERC directives to either create or modify the following definitions: Transmission Operator, Generator Operator, Bulk Power System, Reliable Operation, and Reliability Standard.

Standards affected:

TBD

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-09 IRO Review

Summary:

This project will perform the five-year review of several IRO standards, pursuant to NERC's Rules of Procedure.

Standards affected:

IRO-006, IRO-006-EAST, IRO-008, IRO-009, and IRO-010

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-11 FAC Review

Summary:

This project will perform the five-year review of several FAC standards, pursuant to NERC's Rules of Procedure.

Standards affected:

FAC-010, FAC-011, FAC-014

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-12 PER Review

Summary:

This project will perform the five-year review of several PER standards, pursuant to NERC's Rules of Procedure.

Standards affected:

PER-003, PER-004, PER-005

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-13 NUC Review

Summary:

This project will perform the five-year review of the NUC standard, pursuant to NERC's Rules of Procedure.

Standards affected:

NUC-001

Status:

This is a new project, which will require SAR development. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-14 Risk Analysis

Summary:

This project will develop a standard that requires entities to have and maintain a checklist of potential threats to the power system that must be addressed by each TOP/BA. The checklist would include things like GMD, voltage collapse, and other extreme events.

Standards affected:

New

Status:

This is a new project, which will require SAR development and research. At this time, no estimate for starting the project has been identified.

FUTURE CONSIDERATION

Project 2012-15 Flow Limited Paths

Summary:

The MOD-029 standard includes a provision that, if left uncorrected, could in certain scenarios result in significantly over-conservative ATC values being calculated. This project will address this problem.

Standards affected:

MOD-029

Status:

This is a new project, which will require SAR development and research. At this time, no estimate for starting the project has been identified.

FUTURE DEVELOPMENT

PRC-002-FRCC-1 — FRCC Regional Disturbance Monitoring and Reporting Requirements

Summary:

FRCC plans to convert the existing handbook document, "FRCC Requirements for Disturbance Monitoring Equipment" (revision dated June, 2006) into a new Regional Reliability Standard that complies with the requirements of NERC Reliability Standard, PRC-002-1 — Define Regional Disturbance Monitoring and Reporting Requirements.

Standards affected:

PRC-002-1

Status:

This Regional project is currently on "hold." Based on the NERC Standards Committee reprioritization of NERC Reliability Standard Development Projects resulting in Project 2007-11 Disturbance Monitoring being classified as a "Project in Informal Development," FRCC staff will be re-evaluating the current status of the regional project to determine whether to proceed with the Regional Reliability Standard development or to revise the current FRCC Regional Criteria document "FRCC Requirements for Disturbance Monitoring Equipment."

FUTURE DEVELOPMENT

PRC-003-FRCC-1 — FRCC Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems

Summary:

FRCC plans to convert the existing handbook document "FRCC Requirements for Analysis of Protection Misoperations & Corrective Actions Reporting" (revision dated October, 2003) into a new Regional Reliability Standard, that complies with the requirements of NERC Reliability Standard, PRC-003-1 — Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems.

Standards affected:

PRC-003-1

Status:

Based on the NERC Standards Committee reprioritization of NERC Reliability Standard Development Projects resulting in Project 2010-05.1 Protection Systems: Phase 1 (Misoperations) being classified as a "high priority" project in active development, the Regional project is currently on "hold." The FRCC has revised Regional Criteria documents ("FRCC Requirements for Analysis of Protection Misoperations and Corrective Actions Reporting," revision dateed December 2, 2010) to ensure the procedures comply with the requirements of NERC Reliability Standard, PRC-003-1 — Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems.

FUTURE DEVELOPMENT

PRC-006-FRCC-1 — FRCC Automatic Underfrequency Load Shedding Program

Summary:

FRCC is developing a Regional Reliability Standard to provide last resort system preservation measures by implementing an Underfrequency Load Shedding (UFLS) program. Additional requirements may be needed due to FRCC peninsular geography and limited ties to the north. Operating experience and decades of studies by the FRCC and its predecessor reliability organizations have resulted in a well-developed UFLS program that is very resilient to frequency excursion resulting from severe and extreme contingencies. The standard development project will effectively use the proven high performance characteristics of the existing FRCC UFLS program and refine its requirements and coordination procedures to comply with the requirements of NERC Reliability Standard, PRC-006-1 — Automatic Underfrequency Load Shedding.

Standards affected:

PRC-006-1

Status:

PRC-006-FRCC-1 FRCC Automatic Underfrequency Load Shedding Program has been approved by the FRCC Registered Ballot Body and the FRCC Board of Directors. Based on concerns identified by NERC standards staff and the pending Commission (FERC) approval of the NERC Continent-Wide Reliability Standard PRC-006-1 Automatic Underfrequency Load Shedding and associated Regional variances, the Regional project has been placed on “hold.” The FRCC has since revised Regional Criteria documents (FRCC Automatic Underfrequency Load Shedding Program, revision date: April 7, 2011) to ensure the procedures comply with the requirements of NERC Reliability Standard, PRC-006-1 — Automatic Underfrequency Load Shedding.

FUTURE DEVELOPMENT

PRC-024-FRCC-1 — FRCC Regional Generator Performance During Frequency and Voltage Excursions

Summary:

FRCC is developing a standard to establish "ride through" requirements for generators in the FRCC Region with respect to temporary grid voltage or frequency deviations from their normal range. The Standard should address time duration limits for operation of generator protection for

1) frequencies outside of the 59.5 - 60.5 hertz range,
2) voltages outside of the 95% - 105% range, and
3) generator stator current overloads.

The Standard should address exemption criteria and mitigation measures available for resolving apparent conflicts between generator capabilities and the coordination requirements. Considerable knowledge of grid frequency and voltage excursions and the time limited capabilities of generators to sustain these conditions has been gained through operating experience and previous reliability studies. This standards development project should effectively use this knowledge to define coordination requirements and procedures that comply with the requirements of NERC Reliability Standard, PRC-024-1 — Generator Performance During Frequency and Voltage Excursions.

Standards affected:

PRC-024-1

Status:

Based on the NERC Standards Committee reprioritization of NERC Reliability Standard Development Projects resulting in Project 2007-09 Generator Verification being classified as a "high priority" project in active development, the Regional project is currently on "hold." The FRCC is actively revising Regional Criteria documents (FRCC Generator Coordination Requirements) to ensure the procedures comply with the requirements of NERC Reliability Standard, PRC-024-1 — Generator Performance During Frequency and Voltage Excursions.

2012 DEVELOPMENT

PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding Program

Summary:

The purpose of this Standard is to establish the requirements for NPCC and its members to operate and maintain a coordinated Regional Underfrequency load shedding (UFLS) program. The NPCC's UFLS program will meet the requirements contained in NERC standards, and provide those entities to which it is applicable the guidance necessary to implement it. This standard will also mandate that coordination with neighboring Regional Underfrequency load shedding programs be developed when necessary. The unique character, dispersion, sensitivity and density of the NPCC regional loads emphasize the need for this Standard.

The NPCC regional UFLS standard shall apply to all applicable entities within the Region and sub-regional areas that are both synchronous and asynchronous to the Eastern Interconnection. Quebec UFLS has different parameters, and these are included in the standard and fully coordinated within the Region.

Standards affected:

PRC-006-1

Status:

This Regional project is currently in the standard drafting stage. NPCC expects to complete the drafting of this standard in 2011 and conduct a ballot of stakeholders in the first quarter of 2012. Submission to the NERC Board of Trustees and subsequent filing with FERC is expected to occur in 2012.

FUTURE DEVELOPMENT

PRC-012-NPCC-1 — Special Protection Systems

Summary:

To support and enhance bulk power system reliability, this Standard will establish the criteria for the minimum design objectives and practices for special protection systems (the purpose of which are to detect abnormal system conditions, and take corrective actions other than the isolation of faulted elements to maintain the stability and security of the bulk power system). This Standard will also establish the requirements for close coordination between system planning, design, operating, maintenance and protection functions to ensure that the impacts of special protection system operations do not result in a significant adverse impact.

The proposed Standard will describe the requirements for the design and approval of Special Protection Systems and the technical criteria required to support its implementation. The Standard will also identify the need for close coordination among various parties to ensure that the Special Protection Systems are implemented correctly, and triggers and resulting actions are made known and communicated in an on-line database.

Standards affected:

PRC-012-0

Status:

This Regional project is currently on “hold” pending the completion of the NERC Reliability Standard Development Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS, and the outcome of the work by the NERC SPCS on the definition of SPS.

2011 DEVELOPMENT

MOD-024-RFC-1 — Verification and Data Reporting of Generator Gross and Net Real Power Capability

Summary:

The purpose of this standard is to establish Reliability*First* requirements for verification and data reporting of generator gross and net Real Power capability to support NERC Reliability Standard MOD-024. The objective of the regional standard is to ensure accurate information on generator gross and net Real (MWs) Power capability is available for steady-state models used to assess Bulk Electric System reliability.

Standards affected:

MOD-024-1

Status:

This Regional standard has been approved by the Reliability*First* Board. Currently, VRFs and VSLs are in development. Reliability*First* expects to complete the drafting of the VRFs and VSLs in 2011, with expected submission to the NERC Board of Trustees and subsequent filing with the FERC to occur in 2012.

2011 DEVELOPMENT

MOD-025-RFC-1 — Verification and Data Reporting of Gen Gross and Net Reactive Power Capability

Summary:

The purpose of this standard is to establish Reliability*First* requirements for verification and data reporting of generator gross and net Reactive Power capability to support NERC Reliability Standard MOD-025. The objective of this standard is to ensure that accurate information on generator gross and net Reactive (MVAR) Power capability is available for steady-state models used to assess Bulk Electric System reliability.

Standards affected:

MOD-025-1

Status:

This Regional standard will be submitted to the NERC Board of Trustees in November 2011 and subsequent filing with the FERC is expected to occur in 2012.

2011 DEVELOPMENT

PRC-002-RFC-1 — Disturbance Monitoring and Reporting Requirements

Summary:

The purpose of this standard is to establish Reliability*First* requirements for Disturbance monitoring and reporting to support NERC Reliability Standard PRC-002.

Standards affected:

PRC-002-1

Status:

Reliability*First* is currently working on the technical justification for the locational requirements for DME equipment. This Regional standard has been approved by the Reliability*First* Board. Reliability*First* expects submission of this standard to the NERC Board of Trustees and subsequent filing with the FERC to occur in 2012.

2012 DEVELOPMENT

PRC-006-RFC-1 — Automatic Under Frequency Load Shedding Requirements

Summary:

The purpose of this standard is to establish Reliability*First* requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist in the recovery of frequency following underfrequency events, providing last resort system preservation measures. The standard goes beyond the NERC PRC-006-1 standard and prescribes with more certainty aspects that the Planning Coordinator's UFLS program must contain, further details on certain procedural matters with respect to how islands are addressed, and assessment of UFLS program implementation as well as program design. This standard also attempts further consolidating requirements of the Reliability*First* legacy underfrequency load shedding programs, permitting retirement of legacy documents to ensure appropriate coordination among the Reliability*First* legacy regional UFLS programs.

Standards affected:

PRC-006-1

Status:

This Regional project is currently in the standard drafting stage. Reliability*First* expects to complete the drafting of this standard in 2012, with expected submission to the NERC Board of Trustees and subsequent filing with the FERC to occur later in 2012.

2012 DEVELOPMENT

PRC-012-RFC-1 — Special Protection System Requirements

Summary:

To purpose of the standard is to establish Reliability*First* requirements for the review, development and application of Special Protection Systems (SPS).

Standards affected:

PRC-012-0

Status:

This Regional project is currently in the initial drafting stage. Reliability*First* expects to complete the drafting of this standard in 2012, with expected submission to the NERC Board of Trustees and subsequent filing with the FERC to occur early in 2013.

2011 DEVELOPMENT

PRC-006-SERC-01 — Automatic Underfrequency Load Shedding Requirements

Summary:

The SERC UFLS Standard: PRC-006-SERC-1 ("SERC UFLS Standard") was developed to provide regional UFLS requirements to entities in SERC. UFLS requirements have been in place at a continent-wide level and within SERC for many years prior to implementation of federally mandated reliability compliance standards in 2007.

In 2008, SERC commenced work on PRC-006-SERC-1. NERC also began work on revising PRC-006-0 at a continent-wide level. The SERC standard has been developed to be consistent with the continent-wide UFLS standard.

PRC-006-1 clearly defines the roles and responsibilities of parties to whom the standard applies. The standard identifies the Planning Coordinator ("PC") as the entity responsible for developing UFLS schemes within their PC area. This regional standard PRC-006-SERC-1 adds specificity not contained in the NERC standard for development and implementation of a UFLS scheme in the SERC Region that effectively mitigates the consequences of an underfrequency event.

Standards affected:

PRC-006-1

Status:

This Regional standard will be submitted to the NERC Board of Trustees in November 2011, and subsequent filing with FERC is expected to occur in 2012.

2012 DEVELOPMENT

PRC-006-SPP-1 — Under Frequency Load Shedding

Summary:

PRC-006 (Development and Documentation of Regional UFLS programs) has been identified by NERC as one of the Regional "Fill-in-the Blank" Standards. At a minimum, the requirements developed in this standard need to meet the requirements for the Regional Program as identified in NERC's PRC-006-0. Operating experience and regional studies have resulted in a well developed UFLS program that is very resilient to frequency excursions resulting from severe and extreme contingencies. This standards development effort intends to effectively use the proven high performance characteristics of the existing SPP UFLS program and refine its requirements and coordination procedures through an open process as described in the SPP Standard Development Process Manual.

Standards affected:

PRC-006-1

Status:

This Regional project is currently in the standard drafting stage. SPP expects to complete the drafting of this standard in 2012, with expected submission to the NERC Board of Trustees and subsequent filing with FERC to occur later in 2012.

2011 DEVELOPMENT

IRO-006-TRE-1 — IROL and SOL Mitigation in the ERCOT Interconnection

Summary:

IRO-006-TRE-1 was developed to support bulk power system reliability by providing enforceable requirements associated with certain existing non-routine ERCOT congestion management procedures. This Regional Standard addresses the FERC directive in Paragraph 964 of Order 693, where FERC found that the ERCOT transmission loading relief procedures were superior to the national standard, and directed the ERO to provide Reliability Standards including Requirements, Measures and Levels of Non-Compliance corresponding to the ERCOT procedures for application in the ERCOT Region.

Standards affected:

IRO-006-5 (Note: This regional standard provides additional requirements; it does not alter the requirements or applicability of IRO-006-5.)

Status:

This Regional Standard was approved by the Texas RE Board of Directors on June 28, 2011, and it will be submitted to the NERC Board of Trustees in November 2011. Subsequent filing with FERC is expected to occur in 2012.

2011 DEVELOPMENT

BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region

Summary:

This Regional Standard is intended to support reliability by ensuring adequate primary frequency response performance in the ERCOT Interconnection. The standard addresses frequency response at the Interconnection level, as well as by individual generating units and facilities. Specific maximum governor droop and deadband settings are provided, along with primary frequency response performance standards (initial and sustained) that allow actual unit-specific performance to be measured.

In 2002, NERC approved a regional difference for ERCOT that made it exempt from Requirement R2 in BAL-001-0 (CPS2), because of ERCOT's lack of synchronous connection to other control areas and the nature of the ERCOT energy market. FERC approved the ERCOT regional difference, finding that ERCOT's practice of (a) determining the minimum frequency response needed for reliability, and (b) requiring generators to have specific governor droop, to be a more stringent practice than Requirement R2 in BAL-001-0. FERC directed NERC to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section 5 of the ERCOT protocols. This Regional Standard is responsive to that directive.

Standards affected:

BAL-001-0.1a (Note: This regional standard provides additional requirements; it does not alter the requirements or applicability of the continent-wide standard.)

Status:

This project has been approved by the Texas RE Board of Directors, with expected submission to the NERC Board of Trustees in 2011 and subsequent filing with FERC to occur in 2012.

2012 DEVELOPMENT

BAL-002-WECC-1 — Contingency Reserves

Summary:

On Oct. 21, 2010, FERC found that BAL-002-WECC-1 did not meet the statutory criteria for approval and remanded the regional standard to NERC/WECC for further modification (RM09-15-000; Order 740). FERC held that BAL-002-WECC-1's less stringent requirements had not been supported by the technical data provided.

On remand, the Commission instructed WECC to modify the regional reliability standard to include a number of specific items contained in Order 740. This Request is submitted with the specific and narrow purpose of addressing only those issues mandated for modification in the October 2010 Oder 740.

Standards affected:

BAL-002-WECC-1

Status:

This Regional project is currently in the standard drafting stage. WECC expects to complete the drafting of this standard in 2012, with expected submission to the NERC Board of Trustees and subsequent filing with FERC to occur later in 2012.

2012 DEVELOPMENT

BAL-004-WECC-1 — Automatic Time Error Correction

Summary:

In the order approving BAL-004-WECC-1 the FERC directed WECC to make several clarifying modifications to the standard. FERC directed WECC to use the FERC-approved Process for Developing and Approving WECC standards to make these clarifying modifications

In addition, the WECC staff has identified the opportunity to make additional modifications to the existing standard to clarify the intent without changing the requirements.

There is also confusion regarding the R3 requirement that the ACE used for NERC reports shall be the same ACE as the AGC operating mode in use. This seems to conflict with the NERC response to NOPR comments that entities may use ATEC ACE for control but should use Raw ACE for reporting. WECC is developing a proposed regional variance to BAL-001-0.1a to address this apparent conflict.

Standards affected:

BAL-004-WECC-1
BAL-001-0.1a

Status:

This Regional project is currently in the standard drafting stage. WECC expects to complete the drafting of this standard in 2012, with expected submission to the NERC Board of Trustees and subsequent filing with FERC to occur later in 2012.

2011 DEVELOPMENT

VAR-001-WECC-1 — Voltage and Reactive Control

Summary:

The current draft has been converted from a Standard into a Regional Variance to the NERC VAR-001-2 Standard. The format incorporates the NERC Standard into the document with minor additions to address the scope of the variance. The regional variance specifics are included as Section E of the proposed document (see hyperlink above), and in this case, are intended to replace NERC VAR-001-2 requirements R3 and R4 as noted at the beginning of Section E.

The purpose of this regional variance to a NERC Reliability Standard is to ensure that voltage levels are within limits in real time to protect equipment and the reliable operation of the Western Interconnection. The "Rules of Procedure of the North American Electric Reliability Corporation" (Appendix 3A, page 31) permits the development of a regional variance to a NERC reliability standard on an Interconnection-wide basis when the Regional Reliability Organization has valid justification and when the variance is not inconsistent with or less stringent than the NERC Reliability Standard. The variance is an alternative method for obtaining the same reliability objective as the continent standard and is typically necessitated by a physical difference. A variance is embodied within a reliability standard and as such, if adopted by NERC and approved by the electric reliability organization governmental authority, shall be enforced within the applicable Regional Entity(ies) pursuant to delegated authority.

Standards affected:

VAR-001-2

Status:

This Regional project has been approved by the WECC Board of Directors. WECC expects to submit the draft for the mandatory NERC 45-day comment period in the near future, with expected submission to the NERC Board of Trustees and subsequent filing with FERC to occur later in 2012.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Draft CIP Standards Version 5

Technical Webinar – Part 1

Project 2008-06 Cyber Security Order 706 Standards Drafting Team
November 15, 2011

RELIABILITY | ACCOUNTABILITY






NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda

- Opening Remarks – John Lim, Consolidated Edison, Chair
- V5 Schedule Update – Philip Huff, AECC, Vice Chair
- V5 Standards Format – Sharon Edwards, Duke Energy
- Definitions – William Winters, Arizona Public Service
- CIP-002-5 – John Lim, Consolidated Edison
- Implementation Plan – Philip Huff, AECC
- Q&A – Steven Noess, NERC

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP Version 5 Schedule Update

Philip Huff, Arkansas Electric Cooperative Corporation

RELIABILITY | ACCOUNTABILITY






Posted Materials

Project 2008-06
Cyber Security Order 706 Version 5 CIP Standards

Activity: Version 5 CIP Standards (Phase III)

Status: Ten CIP standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 – collectively referred to as the 'Version 5 CIP Standards'), the associated implementation plan, and the associated definitions are posted for a parallel formal comment period and twelve separate initial ballots (ten for the standards, one each for the definitions and implementation pla). In consideration of the volume of documents and the significant changes to the format and substance of the standards, the Standards Committee authorized extending the comment period to 60 days and the initial ballot window to 20 days, through January 6, 2012.

Draft	Action	Dates	Results	Consideration of Comments
Draft 1 - Version 5 CIP Standards CIP-002-5 CIP-003-5 CIP-004-5 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1 Implementation Plan Definitions		6/11 - 01/06/12		
Supporting Materials Unofficial Comment Form (Word) Mapping Document	Period Info>> Submit Comments>>	11/07/11 - 01/06/12		
CIP-002-4 CIP-003-4 CIP-004-4 CIP-005-4a CIP-006-4c CIP-007-4 CIP-008-4 CIP-009-4 Consideration of Comments from June 2010 Informal Comment Period	Join Ballot Pool Info>> Join>>	11/07/11 - 12/15/11		
CIP Standards Version 5 Webinar Slides		08/24/2011		

Version 5 Standards, Definitions and Implementation Plan

Posted Materials

Project 2008-06
Cyber Security Order 706 Version 5 CIP Standards

Activity: Version 5 CIP Standards (Phase III)

Status: Ten CIP standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 – collectively referred to as the 'Version 5 CIP Standards'), the associated implementation plan, and the associated definitions are posted for a parallel formal comment period and twelve separate initial ballots (ten for the standards, one each for the definitions and implementation pla). In consideration of the volume of documents and the significant changes to the format and substance of the standards, the Standards Committee authorized extending the comment period to 60 days and the initial ballot window to 20 days, through January 6, 2012.

Draft	Action	Dates	Results	Consideration of Comments
Draft 1 - Version 5 CIP Standards CIP-002-5 CIP-003-5 CIP-004-5 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1 Implementation Plan Definitions **Supporting Materials** Unofficial Comment Form (Word) Mapping Document	Initial Ballot Vote>>	12/16/11 - 01/06/12		
	Formal Comment Period Info>>	11/07/11 - 01/06/12		
CIP-002-4 CIP-003-4 CIP-004-4 CIP-005-4a CIP-006-4c CIP-007-4 CIP-008-4 CIP-009-4 Consideration of Comments from June 2010 Informal Comment Period	Join Ballot Pool Info>> Join>>	11/07/11 - 12/15/11		
CIP Standards Version 5 Webinar Slides		08/24/2011		

Unofficial Comment Form and Mapping Document

Posted Materials

Project 2008-06
Cyber Security Order 706 Version 5 CIP Standards

Activity: Version 5 CIP Standards (Phase III)

Status: Ten CIP standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 – collectively referred to as the 'Version 5 CIP Standards'), the associated implementation plan, and the associated definitions are posted for a parallel formal comment period and twelve separate initial ballots (ten for the standards, one each for the definitions and implementation pla). In consideration of the volume of documents and the significant changes to the format and substance of the standards, the Standards Committee authorized extending the comment period to 60 days and the initial ballot window to 20 days, through January 6, 2012.

Draft	Action	Dates	Results	Consideration of Comments
Draft 1 - Version 5 CIP Standards CIP-002-5 CIP-003-5 CIP-004-5 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1 Implementation Plan Definitions **Supporting Materials** Unofficial Comment Form (Word) Mapping Document	Initial Ballot Vote>>	12/16/11 - 01/06/12		
	Formal Comment Period Info>> Submit Comments>>	11/07/11 - 01/06/12		
CIP-002-4 CIP-003-4 CIP-004-4 CIP-005-4a CIP-006-4c CIP-007-4 CIP-008-4 CIP-009-4 Consideration of Comments from June 2010 Informal Comment Period	oin Ballot Pool Info>> Join>>	11/07/11 - 12/15/11		
CIP Standards Version 5 Webinar Slides		08/24/2011		

Version 4 BOT Approved Standards

Posted Materials

Project 2008-06
Cyber Security Order 706 Version 5 CIP Standards

Activity: Version 5 CIP Standards (Phase III)

Status: Ten CIP standards (CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 – collectively referred to as the 'Version 5 CIP Standards'), the associated implementation plan, and the associated definitions are posted for a parallel formal comment period and twelve separate initial ballots (ten for the standards, one each for the definitions and implementation pla). In consideration of the volume of documents and the significant changes to the format and substance of the standards, the Standards Committee authorized extending the comment period to 60 days and the initial ballot window to 20 days, through January 6, 2012.

Draft	Action	Dates	Results	Consideration of Comments
Draft 1 - Version 5 CIP Standards CIP-002-5 CIP-003-5 CIP-004-5 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1 Implementation Plan Definitions **Supporting Materials** Unofficial Comment Form (Word) Mapping Document	Initial Ballot Vote>>	12/16/11 - 01/06/12		
	Formal Comment Period Info>> Submit Comments>>	11/07/11 - 01/06/12		
CIP-002-4 CIP-003-4 CIP-004-4 CIP-005-4a CIP-006-4c CIP-007-4 CIP-008-4 CIP-009-4 Consideration of Comments from June 2010 Informal Comment Period		5/11		
CIP Standards Version 5 Webinar Slides		08/24/2011		

Consideration of Comments from Informal Posting

Comment and Ballot Period

- November 7, 2011 – January 6, 2012
  - Formal 60-day comment period
- December 16, 2011 – January 6, 2012
  - Initial Ballot

Long Term Schedule 2012

January 6 – March 26	• Consideration of comments
March 26 – April 27	• 30-day posting for comment and successive ballot
June 6–22	• Recirculation ballot

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP Version 5 Standards Format

Sharon Edwards, Duke Energy

RELIABILITY | ACCOUNTABILITY






Format – Example/Overview

Rationale for R3: *Malicious code prevention has the purpose of limiting and detecting the addition of malicious code onto the applicable components of a Bulk Electric System (BES) Cyber system. Malicious code (viruses, worms, botnets, targeted code such as Stuxnet, etc.) may compromise the availability or integrity of the BES Cyber System. …*

Summary of Changes: *In prior versions, this requirement has arguably been the single greatest generator of TFE's as it prescribed a particular technology to be used on every CCA regardless of that asset's susceptibility or capability to use that technology. …The drafting team …made… this requirement a competency based requirement where the entity must document how the malware risk is handled for each BES Cyber System, but it does not prescribe a particular technical method nor does it prescribe that it must be used on every component.* ***…****Beginning in paragraph 619-622 of FERC Order 706, …FERC agrees that the standard "does not need to prescribe a single method…"*

R3. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in CIP-007-5 Table R3 – Malicious Code Prevention. [Violation Risk Factor: Medium]

M3. Evidence must include each of the documented processes that collectively include each of the applicable items in CIP-007-5 Table R3 – Malicious Code Prevent. and add'l evidence to demonstrate implementation as described in ..Measures in the table.

CIP-007-5 Table R3 – Malicious Code Prevention			
Part	**Applicability**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems. Associated Physical Access Control Systems Associated Electronic Access Control or Monitoring Systems Associated Protected Cyber Assets	Deploy method(s) to deter, detect, or prevent malicious code.	Evidence may include, but is not limited to, records of the Responsible Entity's performance of these processes (i.e. through traditional antivirus, system hardening, policies, etc.).
Reference to prior version: *CIP-007-4 R4*		**Change Rationale:** *See the Summary of Changes.*	

Format – Rationale/ Summary of Changes

Rationale for R3: *Malicious code prevention has the purpose of limiting and detecting the addition of malicious code onto the applicable components of a BES Cyber system. Malicious code (viruses, worms, botnets, targeted code such as Stuxnet, etc.) may compromise the availability or integrity of the BES Cyber System. …*

Summary of Changes: *In prior versions, this requirement has arguably been the single greatest generator of TFE's as it prescribed a particular technology to be used on every CCA regardless of that asset's susceptibility or capability to use that technology. …The drafting team …made… this requirement a competency based requirement where the entity must document how the malware risk is handled for each BES Cyber System, but it does not prescribe a particular technical method nor does it prescribe that it must be used on every component.* ***…****Beginning in paragraph 619-622 of FERC Order 706, …FERC agrees that the standard "does not need to prescribe a single method…"*

- **Rationale –** Purpose of requirement and any assumptions made about the requirement
- **Summary of Changes –** High level overview of changes in this requirement

Format – High Level/ Requirement and Measure

R3. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable items in CIP-007-5 Table R3 – Malicious Code Prevention. [Violation Risk Factor: Medium]

M3. Evidence must include each of the documented processes that collectively include each of the applicable items in CIP-007-5 Table R3 – Malicious Code Prevent. and add'l evidence to demonstrate implementation as described in ..Measures column of the table.

- **Requirement** specifies what is needed for compliance
- **Measure** explains the type of evidence that must be included to demonstrate compliance
- Most requirements reference a **table** immediately below

Format – Requirement Rows

CIP-007-5 Table R3 – Malicious Code Prevention			
Part	**Applicability**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems. Associated Physical Access Control Systems Associated Electronic Access Control or Monitoring Systems Associated Protected Cyber Assets	Deploy method(s) to deter, detect, or prevent malicious code.	Evidence may include, but is not limited to, records of the Responsible Entity's performance of these processes (i.e. through traditional antivirus, system hardening, policies, etc.).
Reference to prior version: *CIP-007-4 R4*		**Change Rationale:** *See the Summary of Changes.*	

- **Requirement row specifies:**
  - Sub requirement number
  - Applicability – Identifies the groups of assets which must comply with requirement
  - Requirement – Specifies what is needed for compliance with sub requirement
  - Measures – Explains how compliance with sub requirement may be demonstrated
  - Reference to prior to version – Identifies where the requirement was previously found in CIP

Format – Applicability

- **All Responsible Entities**
- **BES Cyber System:** One or more BES Cyber Assets that are typically grouped together, logically or physically, to operate one or more BES Reliability Operating Services
  - High Impact BES Cyber Systems
  - Medium Impact BES Cyber Systems
  - Low Impact BES Cyber Systems
- **Electronic Access Control or Monitoring Systems:** Cyber Assets used in the access control or monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems

Format – Applicability

- **Physical Access Control Systems:** Cyber Assets that control, alert, or log access to the Defined Physical Boundary(s), exclusive of locally mounted hardware or devices at the Defined Physical Boundary such as motion sensors, electronic lock control mechanisms, and badge readers.
- **Protected Cyber Asset:** A Cyber Asset connected using a routable protocol within an Electronic Security Perimeter that is not part of the BES Cyber System. A Transient Cyber Asset is not considered a Protected Cyber Asset.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Additional Format

- The following slide illustrates additional format:
  - Identification of Assets
  - Application of Cyber Security Controls commensurate with risk to the BES

High Level Structure Assets/Controls

High Impact	**Large Control Centers**
Medium Impact	**Generation + Transmission Small Control Centers That meet Criteria** • **Generation- >1500 MW** • **Gen - BlackstartResource** • **Substation - >500 KV** • **Sub - Blackstart Path** • **See additional criteria in posting**
Low Impact	**Everything else**

Additional layer of Controls apply Only to High Impact BES Cyber Systems

CIP 004	CIP 006	CIP 007	CIP 010	CIP 010
Revoke individual user acct access within 30 days	2 or more physical controls	Review a summary or sampling of logged events every 2 weeks	For each change to baseline, test and document CS controls	Perform Active Vulner. Assessment every 3 years (test environment)
Chg. passwords for shared accts within 30 days			Monitor for changes to the baseline	Prior to adding a device perform Vulnerability Assessment

Controls for Medium and High BES Cyber System Controls roughly equate to previous versions of CIP with some modifications:

- FERC Order 706 Directives have been incorporated into requirements
- Access Control requirements previously in CIP 003, 004, 005, and 007 are combined
- Efforts have been made to eliminate the need for TFE's
- New Standards for Info. Protection and Configuration Mgt/Vul. Assessments
- Efforts to remove documentation only based requirements. Performance based std.
- Other modifications for problem areas, i.e., passwords, transient assets, etc.

Requirements that apply to LOW Impact BES Cyber Systems include Governance and non-technical controls

CIP 003	CIP 004	CIP 005	CIP 006	CIP 007	CIP 008
ID Sr. Manger + Maintain CS Policy	Awareness	If routable protocol is used, define technical and procedural controls to restrict access	Define technical and procedural controls to restrict physical access	Initially change default passwords	Incident Response Plan + Testing and Review of Plan

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP Version 5 Definitions

William Winters, Arizona Public Service

RELIABILITY | ACCOUNTABILITY






NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Definitions

- Terms already defined in the Glossary of Terms used in NERC Reliability Standards are not repeated here
- New or revised definitions become approved when the proposed standard is approved
- When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary
- New defined terms are underscored
- For existing glossary terms, new language is shown as underscored, while deleted language is shown as stricken

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Definitions
21 New or Revised

	CIP002	CIP003	CIP004	CIP005	CIP006	CIP007	CIP008	CIP009	CIP010	CIP011
BES Cyber Asset	x					x			x	x
BES Cyber Security Incident						x	x		x	
BES Cyber System	x	x	x	x	x	x		x		
BES Cyber System Information										x
BES Reliability Operating Services	att 1									
CIP Exceptional Circumstance			x			x			x	
CIP Senior Manager	x	x	x			x			x	
Control Center	att 1									
Cyber Assets				x					x	
Defined Physical Boundary (“DPB”)					x					
Electronic Access Control or Monitoring Systems					x	x			x	
Electronic Access Point (“EAP”)				x		x				
Electronic Security Perimeter (“ESP”)				x						
External Connectivity										
External Routable Connectivity				applicability						
Interactive Remote Access				x						
Intermediate Device				x						
Physical Access Control Systems					x	x				
Protected Cyber Asset				x		x				
Reportable BES Cyber Security Incident							x			
Transient Cyber Asset						x				

Definitions Retired and Replaced

- Critical assets
  - Replaced by CIP002 Attachment 1 and BES Reliability Operating Services definition
- Critical cyber assets
  - Replaced by BES Cyber Asset and BES Cyber System
- Physical security perimeter
  - Replaced by Defined Physical Boundary
  - No more “six-wall” specification

Definitions
New Scoping Concepts

- BES Cyber Asset
  - A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its operation, mis-operation, or non-operation, when required, adversely impact one or more BES Reliability Operating Services.
  - This is regardless of the delay between the point in time of unavailability, degradation, or misuse of the Cyber Asset and the point in time of impact on the BES Reliability Operating Services.
  - The timeframe is not in respect to any cyber security events or incidents, but is related to the time between when the Cyber Asset can send or receive instructions to operate and the time in which that operation occurs and impacts the BES.
  - Redundancy shall not be considered when determining availability.
  - A Transient Cyber Asset is not considered a BES Cyber Asset.
- BES Cyber System
  - One or more BES Cyber Assets that are typically grouped together, logically or physically, to operate one or more BES Reliability Operating Services.

Definitions Nested for Impact

- **BES Reliability Operating Services**

  BES Reliability Operating Services are those services contributing to the real-time reliable operation of the BES. They include the following Operating Services:

  - Dynamic Response to BES conditions
  - Balancing Load and Generation
  - Controlling Frequency (Real Power)
  - Controlling Voltage (Reactive Power
  - Managing Constraints
  - Monitoring & Control
  - Restoration of BES
  - Situational Awareness
  - Inter-Entity Real-Time Coordination and Communication

- **Integral to CIP002 scoping of BES Cyber System and BES Cyber Asset impact levels**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP-002-5: BES Cyber Asset and BES Cyber System Categorization

John Lim, Consolidated Edison

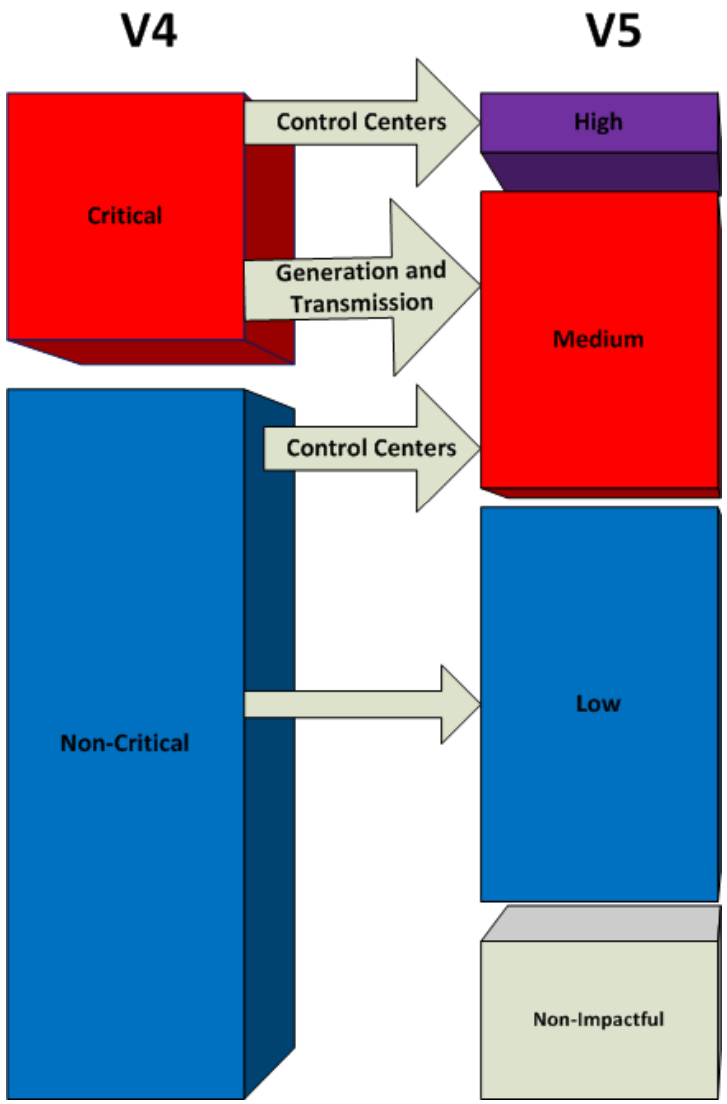
RELIABILITY | ACCOUNTABILITY






Levels of Impact

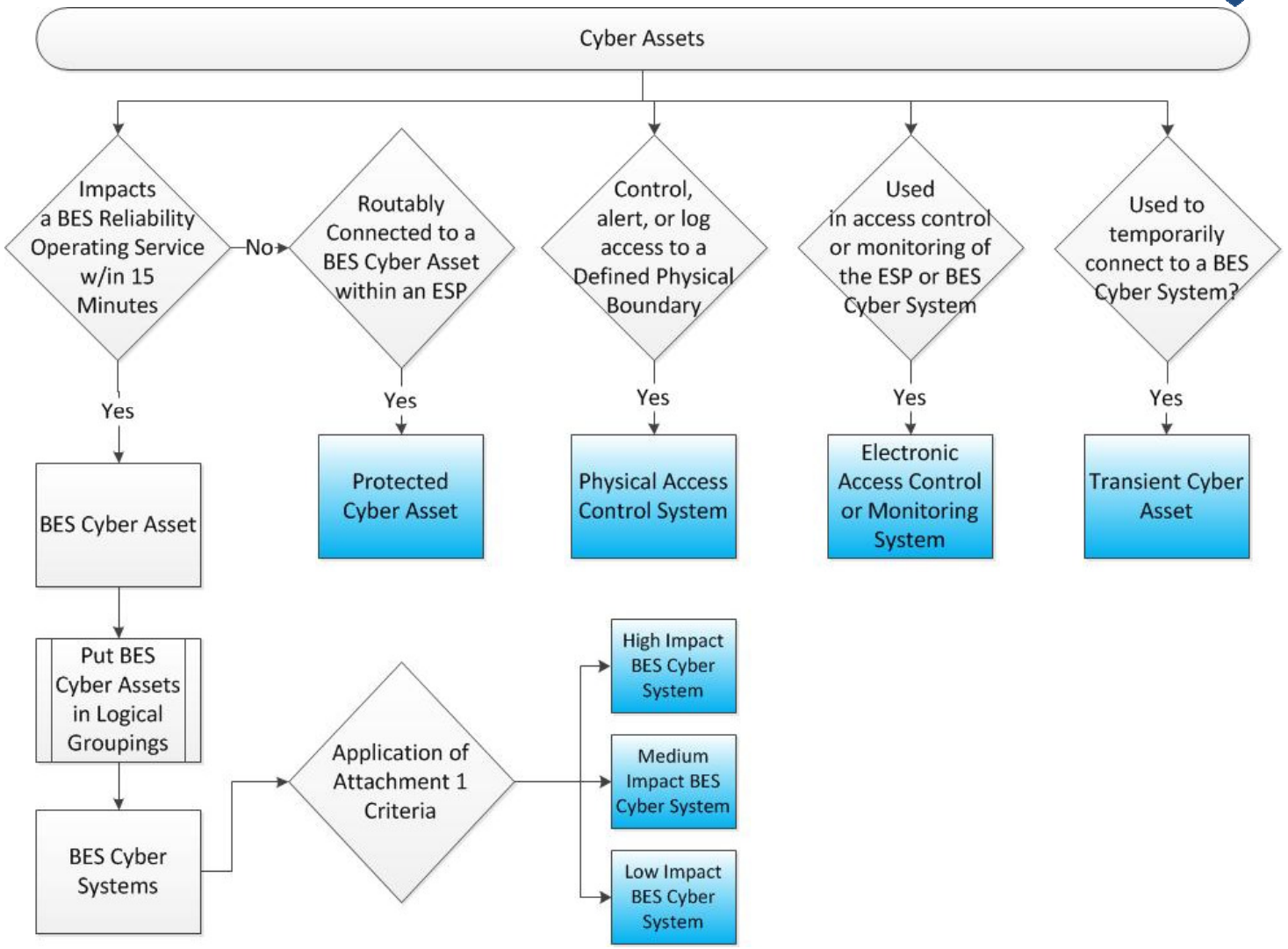
- High Impact
  - Large Control Centers
  - CIP-003 through 009+
- Medium Impact
  - Generation and Transmission
  - Other Control Centers
  - Similar to CIP-003 to 009 v4
- All other BES Cyber Systems
  - Security Policy
  - Security Awareness
  - Incident Response
  - Boundary Protection



Summary of Modifications CIP-002-5

- Categorized list of high and medium impact
  - Attachment 1 criteria
- Other BES Cyber Systems deemed to be low impact by default
- Update required lists for significant changes to BES that affect high/medium categorization
- Senior manager or delegate annual review and approval

Categories of Cyber Assets Under CIP v5



CIP-002-5 Impact Criteria (Attachment 1)

- High: Large control centers (e.g., RC, BA, TOP)
- Medium: Significant impact field assets, other control centers
- Other BES Cyber Systems deemed to be low impact by default
- Based on V4 criteria
  - Modification to transmission voltage threshold

CIP-002-5 R1

- Identify and categorize its high and medium impact BES Cyber Assets and BES Cyber Systems according to the criteria contained in *CIP-002-5 Attachment I – Impact Categorization of BES Cyber Assets and BES Cyber Systems*
- All other BES Cyber Assets and BES Cyber Systems that it owns shall be deemed to be low impact and do not require discrete identification
- *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

CIP-002-5 R1 – Part 1.1

- Update the identification and categorization within 30 calendar days of a change to BES Elements and Facilities:
  - Intended to be in service for more than 6 calendar months and
  - Causes a change in the identification or categorization of the BES Cyber Assets or BES Cyber Systems from a lower to a higher impact category.

CIP-002-5 R2

- CIP Senior Manager or delegate approve the identification and categorization required by R1:
  - Initially upon the effective date of the standard and
  - At least once each calendar year thereafter, not to exceed 15 calendar months between approvals
- *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

CIP-002-5 Attachment 1 (1 of 9) High Impact

- Each BES Cyber Asset or BES Cyber System that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact one or more BES Reliability Operating Services used by and located at:
  - 1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
  - 1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority.
  - 1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator or Transmission Owner that includes control of one or more of the assets identified in criteria 2.2, 2.5, 2.6, 2.7, 2.8, 2.9, 2.10, 2.11 or 2.12 below.
  - 1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generation Operator that includes control of one or more of the assets identified in criteria 2.1, 2.3, 2.4, or 2.12, below.

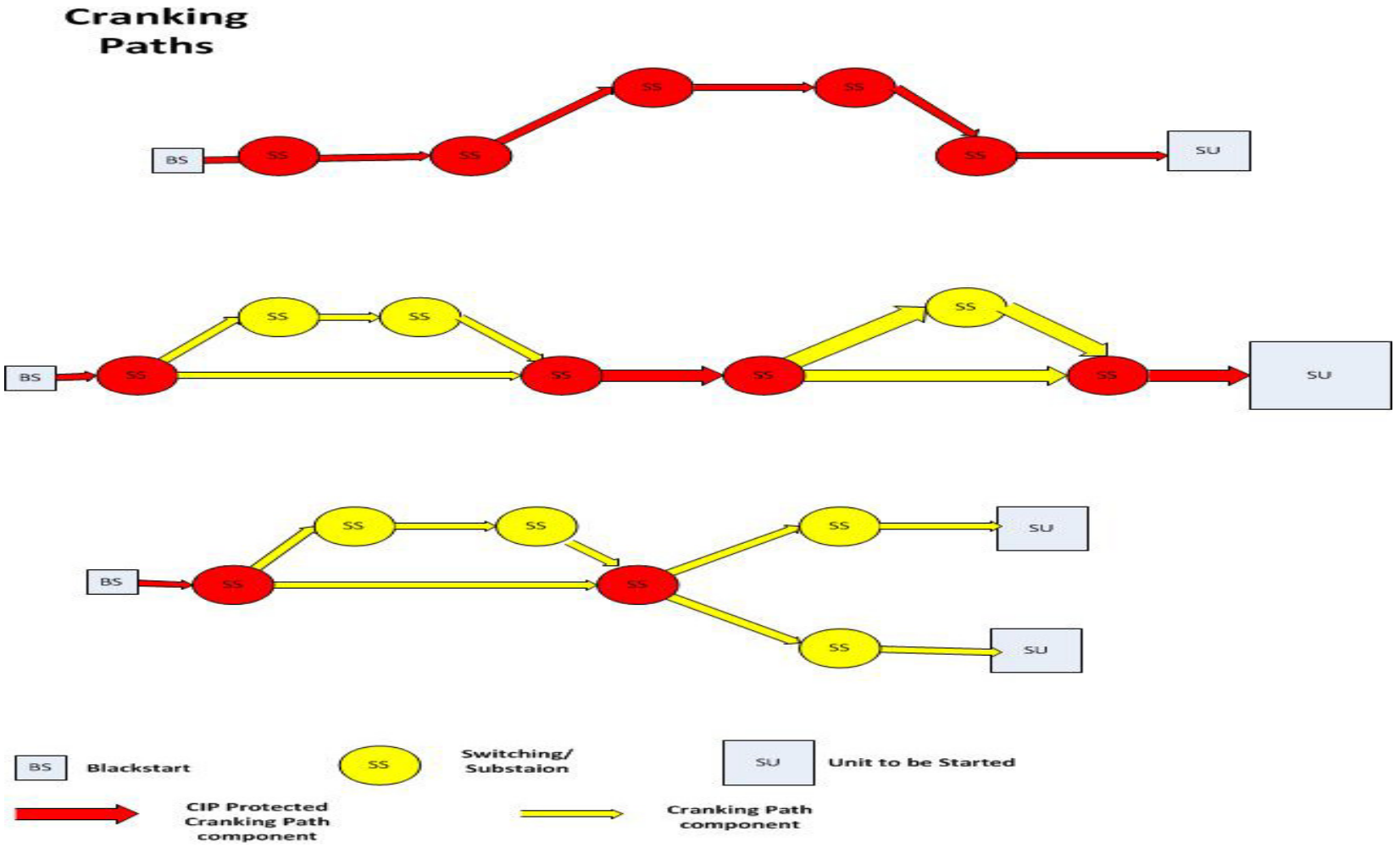
CIP-002-5 Attachment 1 (2 of 9) Medium Impact

- Each BES Cyber Asset or BES Cyber System, not included in Section 1, above, that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact one or more BES Reliability Operating Services for:
  - 2.1. Generation with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single interconnection.
  - 2.2. An aggregate net Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities).
  - 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates and informs the Generator Owner or Generator Operator as necessary to avoid BES Adverse Reliability Impacts in the long-term planning horizon.

CIP-002-5 Attachment 1 (3 of 9) Medium Impact

- 2.4. Each Blackstart Resource identified in its Transmission Operator's restoration plan.
- 2.5. The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource:
  - Up to and including the first interconnection point of the generation unit(s) to be started, or
  - up to the point on the Cranking Path where two or more path options exist and including any single failure points in the Cranking Path to and including the first interconnection point of the generation unit(s) to be started, or
  - up to and including the point on the Cranking Path where two or more path options exist to two or more independent generation unit(s) to be started as identified in its Transmission Operator's restoration plan.

CIP-002-5 Attachment 1 (4 of 9)
Medium Impact



CIP-002-5 Attachment 1 (5 of 9) Medium Impact

- 2.6. Transmission Facilities operated at 500 kV or higher.
- 2.7. Transmission Facilities operating at 200 kV or higher, but at less than 500 kV,… connected to three or more transmission stations or substations…and where the "total weighted aggregate value" … exceeds a value of 3,000.

Voltage Value of a Line	Weight Value per Line
200 kV to 299 kV	700
300 kV to 499 kV	1300

CIP-002-5 Attachment 1 (6 of 9) Medium Impact

- 2.8. Transmission Facilities … critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
  - In the WECC Region, Transmission Facilities … critical to the derivation of SOLs and their contingencies for transmission paths listed in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System".
- 2.9. Flexible AC Transmission Systems (FACTS), … critical to the derivation of Interconnection Reliability Operating Limits (IROLs), and their associated contingencies.
  - In the WECC Region, Flexible AC Transmission Systems (FACTS), … critical to the derivation of SOLs and their contingencies for transmission paths listed in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System."

CIP-002-5 Attachment 1 (7 of 9) Medium Impact

- 2.10. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.11. Each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system… that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations.
  - In the WECC Region, each Special Protection System (SPS), Remedial Action Scheme (RAS) or automated switching system …that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more System Operating Limits (SOLs) violations … in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" and each RAS listed in the most current table titled " Major WECC Remedial Action Schemes (RAS)."

CIP-002-5 Attachment 1 (8 of 9) Medium Impact

- 2.12. Each system or Facility that performs automatic load shedding,… of 300 MW or more implementing Under Voltage Load Shedding (UVLS) or Under Frequency Load Shedding (UFLS) as required by its regional load shedding program.
- 2.13. Control Centers not included in High Impact Rating (H), above, that perform (1) the functional obligations of Transmission Operators or Transmission Owners; or (2) generation control centers that control 300 MW or more of generation.

CIP-002-5 Attachment 1 (9 of 9) Low Impact

Low impact:

- All other BES Cyber Assets and BES Cyber Systems not categorized in Section 1 as having a High Impact Rating (H) or Section 2 Medium Impact Rating (M).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

CIP Version 5 Implementation Plan

Philip Huff, Arkansas Electric Cooperative Corporation

RELIABILITY | ACCOUNTABILITY






Effective Date

The later of:

- January 1, 2015
- 18 Months Minimum – seven calendar quarters after regulatory approval

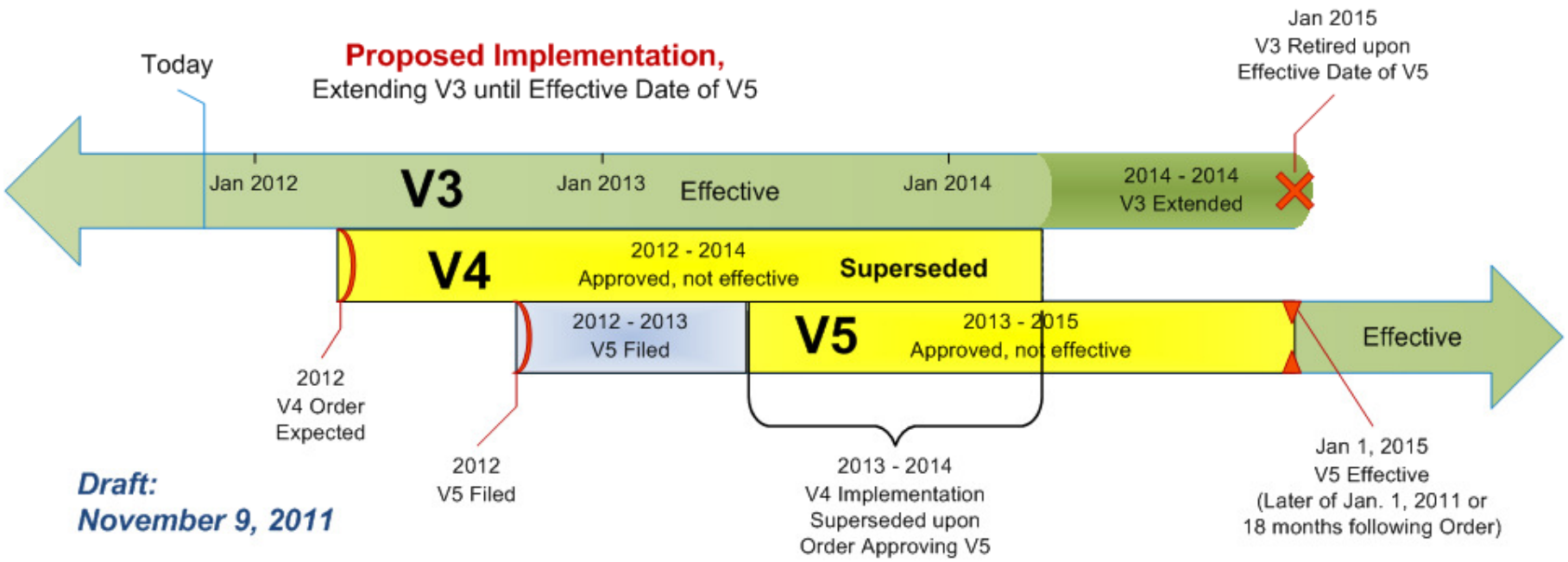
Effective Date – Version Transition

Notwithstanding any order to the contrary, CIP-002-4 through CIP-009-4 do not become effective, and CIP-002-3 through CIP-009-3 remain in effect and are not retired until the effective date of the Version 5 CIP Cyber Security Standards under this implementation plan.

Effective Date – Version Transition

Implementation Plan for Version 5 of CIP Cyber Security Standards

(Graphic for illustrative and comparative purposes only; dates are estimates only and based on assumptions. There is no way to know or anticipate when FERC may take action on pending matters)



Effective Date – Canadian Entities

In those jurisdictions where no regulatory approval is required, the standards shall become effective on the first day of the seventh calendar quarter following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Implementation Plan Other Changes

- **Single Implementation Plan**
  - Incorporated Unplanned Changes from “Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities”
- **Single Effective Date**
  - No staggered implementation. No Compliant/Auditably Compliant dates

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Questions?

- Please submit your questions via the ReadyTalk chat window
- Point of Contact: Steven Noess, NERC
  - steven.noess@nerc.net
- Slides and recording of Webinar will be posted to the NERC website
- Key Dates:
  - Technical Webinar, Part II: November 29, 2011, 1:00 – 3:00 p.m. ET
  - CIP Version 5 Balloting and Process: December 13, 2011 (tentative)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BAL-003-1 Standard

Project 2007-12 Frequency Response and Frequency Bias Setting – Industry Webinar

Terry L. Bilke – Midwest ISO, Inc.
David F. Lemmons – Xcel Energy, Inc.
Sydney L. Niemeyer – NRG Texas LP

November 14, 2011

RELIABILITY | ACCOUNTABILITY






BAL-003-1 Information

- Standard posted for formal comment from October 25, 2011 through December 8, 2011
- Standard posted for Industry Ballot from November 29, 2011 through December 8, 2011
- Link to BAL-003-1 Frequency Response and Frequency Bias Setting Standard Website
  - http://www.nerc.com/filez/standards/Frequency_Response.html

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda

- Frequency Response and Standard background
- Overview of BAL-003-1
- Requirements and Measures
- Bias Setting Process
- Interconnections and Balancing Authority (BA) Frequency Response Obligation (FRO)
- Frequency Response Measure (FRM)
- FRS Form 1 and Form 2
- Questions

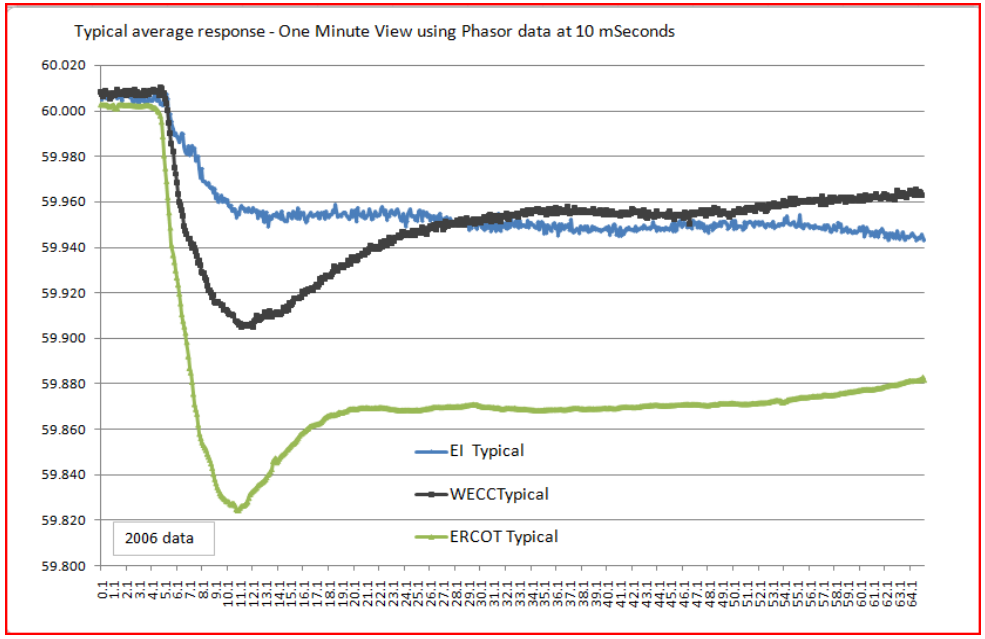
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Background

- FERC Order 693 directed specific changes for BAL-003
- Standard Authorization Request (SAR) drafted to address the issues identified by FERC
- NERC Operating Committee (OC) authorized Frequency Response field trial to help standard development at the June 7–8, 2011 OC meeting
- Frequency Response, termed beta (β), is
  - A fundamental reliability service
  - A combination of governor and load response

Background

- Following a generator (or load loss)
  - β stabilizes frequency at a new point
  - The contingent BA is responsible for replacing the lost resource in order to release Frequency Response of non-contingent BAs within the Interconnection



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Frequency Response

- Frequency Bias (B) is not the same as Frequency Response (β)
  - Frequency Response is actual MW contribution to stabilize frequency
  - Bias is an approximation of β used in the Area Control Error (ACE) equation – prevents Automatic Generation Control (AGC) withdrawal of β
- Both are negative numbers (as frequency drops, MW output increases and vise versa)
- Both are measured in MW/0.1Hz
- Bias (absolute value) must be $\geq$ β (absolute value)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Frequency Response

- In the East, B (absolute value) is about 2-3 x as large as β (absolute value)
- Bias (absolute value) must be at least 1% of BA peak load under current standard
- If there is to be a difference between B and β, it is preferable to be over-biased

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Original Goals

- Original SAR
  - Objectively benchmark and track BA and Interconnection performance
    - Confirm trends
    - Learn why and where response trending down
  - Additional generator level data from low responders
  - Accurate data for models
  - Enable technically sound decisions on setting any future performance obligations
- FERC Order No. 693 directed additional work

Reasons for Change

- FERC directives in Order No. 693
  - Determine the appropriate periodicity of Frequency Response surveys
  - Define the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the Frequency Response is achieved
- Details are described in the *Background Document* that is posted with the standard
- NERC has committed to file BAL-003-1 with FERC in May of 2012

BAL-003-1 Overview

- Drafting team proposing 5 requirements
  - Frequency Response to frequency events
  - Frequency Bias Setting implementation*
  - AGC to operate in Tie Line Bias mode*
  - Appropriate Frequency Bias Setting for those providing Overlap Regulation Service*
  - And Minimum Frequency Bias Setting*

*Similar to existing standard

Requirement R1

- Each BA or Reserve Sharing Group (RSG) shall achieve an annual FRM (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its FRO to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of Frequency Response in the Interconnection

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Attachment A

- Details how to calculate FRM based on actual responses to frequency excursions throughout a year
- Calculation will be for both frequency drops and frequency spikes
- NERC will publish list of events for each interconnection at least quarterly so BAs can calculate performance throughout the year
- More detail provided later in presentation

Measure M1

- The BA or RSG shall have FRS Form 1 with data to show that its FRM is equal to or more negative than FRO to demonstrate compliance with Requirement R1
  - Data required to fill out forms is scan rate data from Emergency Management System (EMS) for time, frequency and Net Actual Interchange

Requirement R2

- Each BA not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control
  - Similar to existing R1

Measure M2

- The BA shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was entered into its ACE calculation on the date specified or other evidence to demonstrate compliance with Requirement R2

Requirement R3

- Each BA not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the BA's Area
  - Similar to existing R3

Measure M3

- The BA shall have evidence such as a dated operating log, database or list in hard copy or electronic format, or operator interviews supported by other evidence showing the AGC operating mode including explanation when operating in other than Tie Line Bias mode to demonstrate compliance with Requirement R3

Requirement R4

- Each BA that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to the sum of the Frequency Bias Settings of the participating BAs as validated by the ERO or calculate the Frequency Bias Setting based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled
  - Similar to existing R6

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Measure M4

- The BA shall have evidence such as a dated operating log, database, or list in hard copy or electronic format showing when Overlap Regulation Service is provided including Frequency Bias Setting calculation to demonstrate compliance with Requirement R4

Requirement R5

- In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following:
  - The minimum percentage of the BA Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B
  - The minimum percentage of the BA Area's estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment B

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Attachment B

- Allows for the minimum Frequency Bias Setting to be reduced based on measured Frequency Response in each Interconnection
- Initial minimum setting to be .8% of peak load or generation (reduction from existing 1.0% of peak load or generation)
- More information will be provided later in presentation

Measure M5

- The BA shall have evidence such as dated data plus documented formula to support the calculation retained in either hardcopy or electronic format showing the monthly average Frequency Bias Setting or other evidence to demonstrate compliance with Requirement R5

Bias Setting Process

- The Bias Setting process will be very similar to what is done today
- Form 1 will automatically calculate a proposed Bias Setting for the upcoming year
  - The data submitted by the BA will be validated
  - CPS Limits, Bias Settings and FRO for upcoming year will be posted on NERC website
- BAs will be given an implementation date for the new Bias Setting (typically March 1)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Attachment A

- Sets out the ERO's criteria for selecting events used for Bias Setting and FRM
- Measurement Cycle is December 1 (previous year) through November 30 (current year)
- Outlines the Frequency Response Obligations in each Interconnection and the allocation process to BAs
- Field Test proposes to use historic peak load and generation data from FERC Form 714 as basis for allocation to BAs

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Example of Annual Cycle

- January 10, 2012: BAs submit FRS Forms 1 and 2
- January-February 2012: NERC and RS validate data, NERC posts CPS, Bias Setting, FRO
- March 1, 2012: Implement 2012 Bias Settings
- March-November 2012: NERC periodically posts and updates list of candidate events likely to be used for current year's FRM and next year's Bias Setting
- December 7, 2012: NERC posts:
  - Official list of events for Bias Setting and FRM (Forms 1 and 2)
  - BAs notified

Attachment B

- Adjusting Minimum Bias Setting
  - Present minimum Bias Setting is 1% of peak/0.1Hz
  - For most BAs, Frequency Response is < this 1% value
  - Control theory says Bias and Frequency Response should closely match
  - Attachment B lays out process for an Interconnection to adjust minimum Bias Setting
  - Field test in 2012 to adjust minimum Bias Settings
    - 0.8% of peak
    - If no issues observed, process used in Attachment B will be used to consider further reduction in out years

Frequency Response Obligation

- The process will determine an FRO for each Interconnection
- The Interconnection FRO will be allocated across all BAs in that Interconnection

IFRO Calculation

	Eastern	Western	Texas	Québec	
Resource Loss Criteria	4,500	2,740	2,750	1,700	MW
Base IFRO	-1,125	-548	-229	-113	MW/0.1Hz
25% Margin	-281	-137	-57	-28	MW/0.1Hz
IFRO	-1,406	-685	-286	-141	MW/0.1Hz
IFRO as % of Interconnection Load	0.233 %	0.460 %	0.448%	0.688 %	

Where

Interconnection	Resource Contingency	Basis	MW
Eastern	Largest Resource Event in Last 10 Years	August 4, 2007 Disturbance	4,500
Western	Largest N-2 Event	2 Palo Verde Units	2,740
Texas	Largest N-2 Event	2 South Texas Project Units	2,750

Balancing Authority FRO

- BAs will be allocated a portion of the Interconnection FRO based on peak load and generation
- The drafting team recommends historical peak load and generation from FERC Form 714 or comparable
- NERC will do this allocation each year, probably through the Resources Subcommittee
- NERC will allocate FRO based on formula and transmit this information to each BA with the Frequency Bias Setting
- This allocation should not change for the 12 month period used for evaluation of compliance

Frequency Response Measure

- The BA FRM will be compared to the BA FRO to determine compliance with R1
- FRM is calculated using the frequency events listed on FRS Form 1 at the end of each 12 month period
  - The 12 months run from December 1 through November 30 of the following calendar year

Calculation of BA FRM

- BA will fill out FRS Form 2 for each event listed on FRS Form 1
- Summary information from each FRS Form 2 will be moved into FRS Form 1
- FRS Form 1 will use all events to determine median response
- Median response is the BA FRM for that period

Selection of Events

- Minimum of 25 events will be used for FRM calculation
- If few events occur during a 12 month period, older events will be used to make 25 events
- List will be Interconnection specific
- Determination of “event” based on specifics in Attachment A

FRS Form 1 and 2

- Phase 1 successes and problems
- Lessons learned
- Details of each Form

Field Trial Phase I Participation

- East
  - Form 1 and 2 provided: 30 BAs
  - Form 1 only provided: 5 BAs
  - No Form provided: 32 BAs
- West
  - Form 1 and 2 provided: 13 BAs
  - Form 1 only provided: 0 BAs
  - No Form provided: 24 BAs
- Hydro-Quebec and Texas
  - Form 1 and 2 provided: 2 BAs

Form 1 Issues

- East
  - Event time on two events incorrect
  - Two events from 2009
- West
  - Event selection, out of 15 events
    - Three events had two contingencies – March 7, March 22 and July 3
    - Two events: B Value recovered within normal governor dead-bands – May 11 and May 24
    - Three events: Slow decay in frequency – May 31, March 14 and March 16
    - Good events to evaluate – March 26, April1, April 28, June 1, June 24, June 25 and July 10

Form 1 Issues

- Hydro-Quebec
  - Event selection, multiple events where frequency recovered to pre-disturbance level before the end of the B Value time period (20 to 52 seconds)
- Event selection process requires proper review before the event is placed on Form 1
  - Team from each Interconnection should be involved in the selection of events
  - Frequency graphs of each event should be generated before final selection

Form 1 Improvements

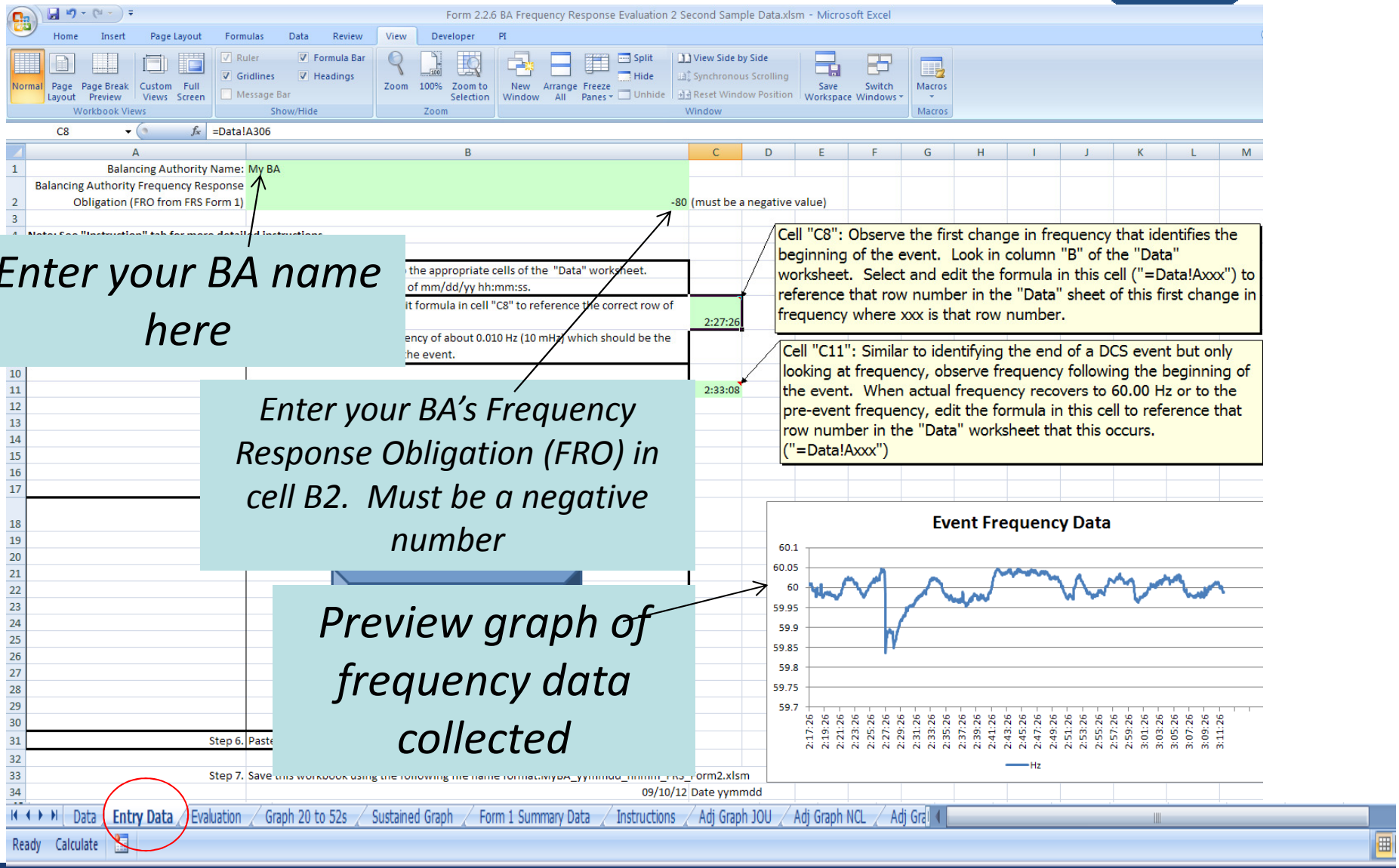
- Event selection process improving
  - Process in place for event identification
  - Process in place for event review and selection
  - Included frequency graph of each event selected in Form 1 for the East and West
  - Added UTC time of event

FRS Form 2

- FRS Form 2 receives BA AGC scan rate data to measure the BA's primary Frequency Response performance to a single, identified frequency perturbation on the system
- Measures the change in Net Actual Interchange and the change in frequency due to the perturbation
- Standardizes the measurement process for all BAs in all Interconnections
- Value B average period of 20 to 52 seconds selected as the standard measure
  - Other average periods removed from both Forms

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Entry Data Worksheet



Enter your BA name here

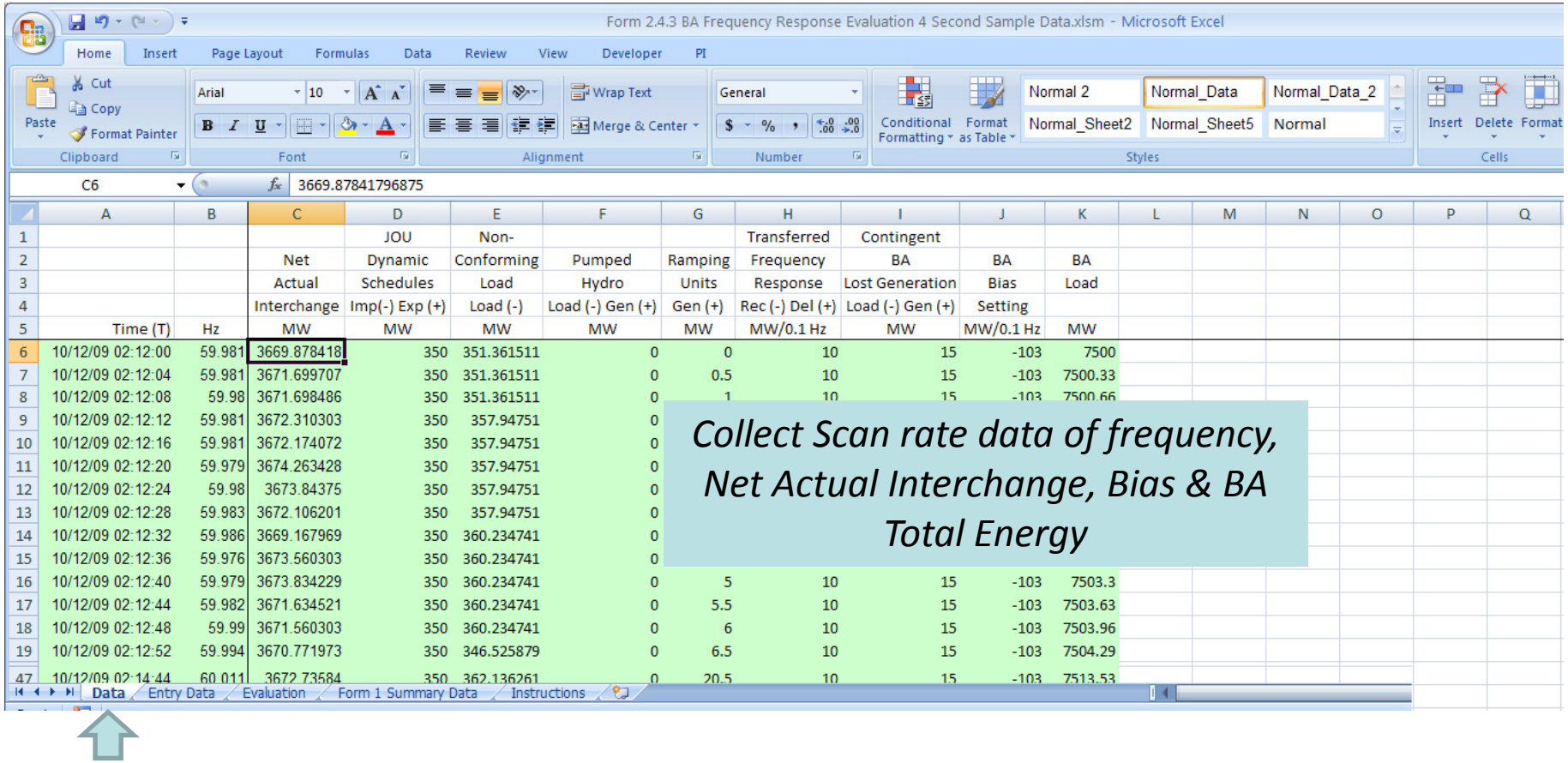
Enter your BA's Frequency Response Obligation (FRO) in cell B2. Must be a negative number

Preview graph of frequency data collected

Cell "C8": Observe the first change in frequency that identifies the beginning of the event. Look in column "B" of the "Data" worksheet. Select and edit the formula in this cell ("=Data!Axxx") to reference that row number in the "Data" sheet of this first change in frequency where xxx is that row number.

Cell "C11": Similar to identifying the end of a DCS event but only looking at frequency, observe frequency following the beginning of the event. When actual frequency recovers to 60.00 Hz or to the pre-event frequency, edit the formula in this cell to reference that row number in the "Data" worksheet that this occurs. ("=Data!Axxx")

Collect Data and Place in Form 2



"Data" Tab: BA Event scan rate data placed in specific columns

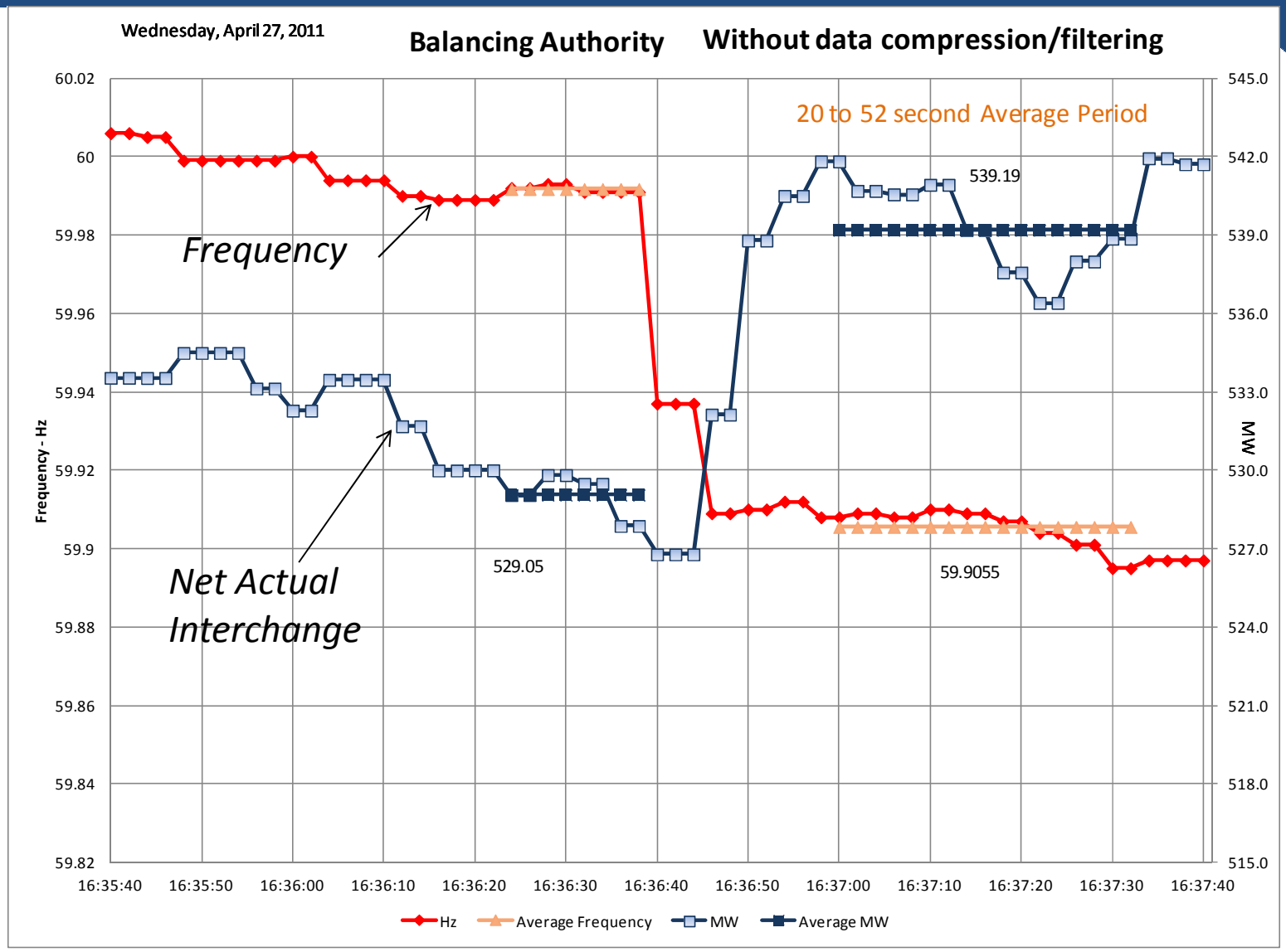
Lessons Learned on Data Collection

- Date/Time data must be in time format, it cannot be text.
  - If your historian returns text for the time values, create correct time format data in the time field. Evaluation requires a valid time format.
- Frequency data and Net Actual Interchange data must be discrete data values each sample (AGC scan). Data compression techniques should not be used on this data.
- Must have a minimum of two minutes of data before beginning of the event for full analysis.

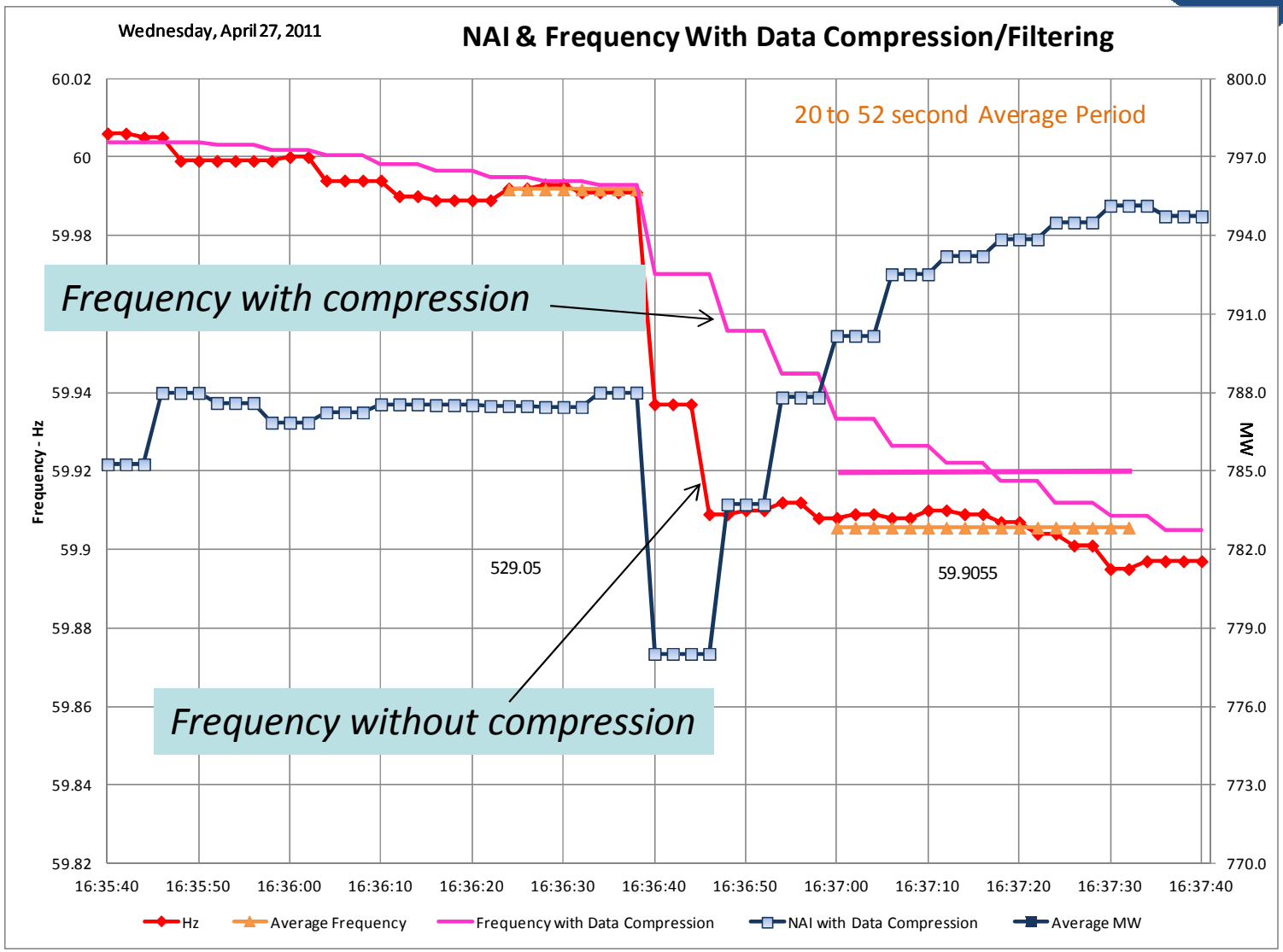
Lessons Learned on Data Collection

- Form 1 contains the exact time of t(0) using 2 second scan rate data. If you begin data collection exactly 10 minutes before this time, t(0) should always be in the same row in the data worksheet.
  - Using different scan rates may cause you to adjust up or down one row when setting t(0) but it should always be within one or two rows on each event.
- Some BAs added an additional worksheet into Form 2 for their data collection formulas and retrieval.
- Some BAs built automatic detection of t(0) and the recovery period time.

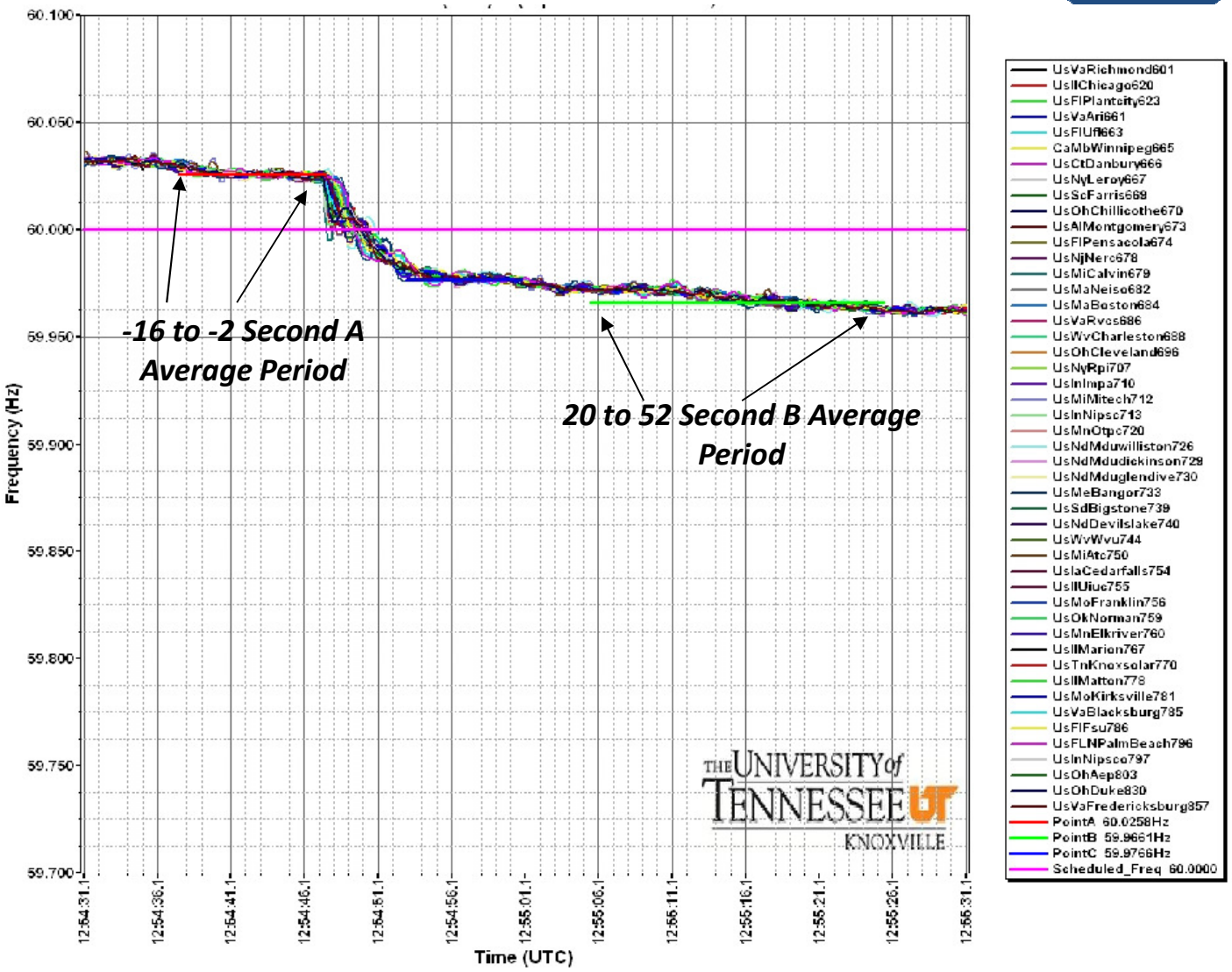
Example of No Data Compression



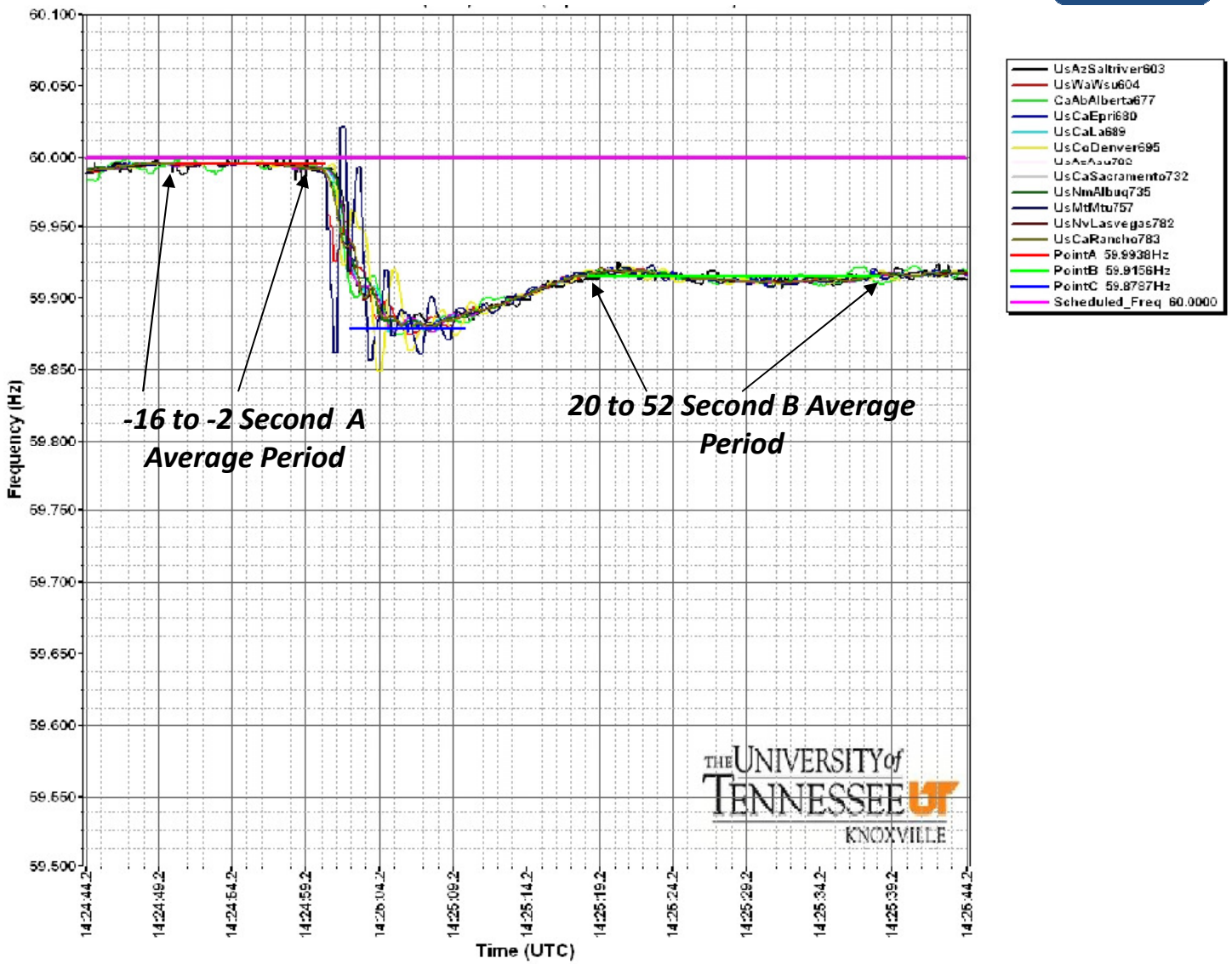
Hz and NAI with Compression



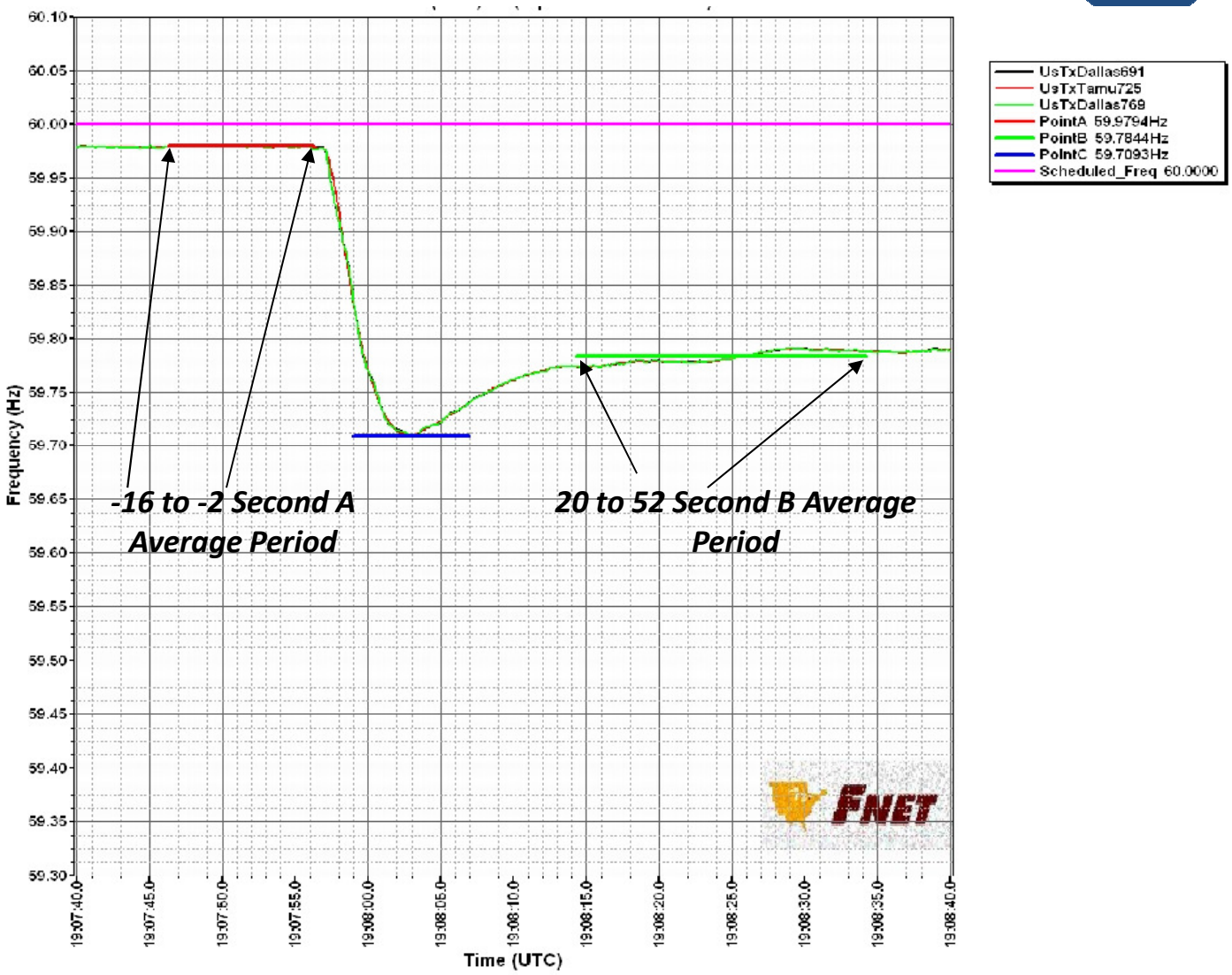
Frequency Diversity Across the Eastern U. S.



Frequency Diversity Across the Western U. S.



Frequency Diversity Across Texas



FNET Graphs

Courtesy of …

THE UNIVERSITY of TENNESSEE KNOXVILLE

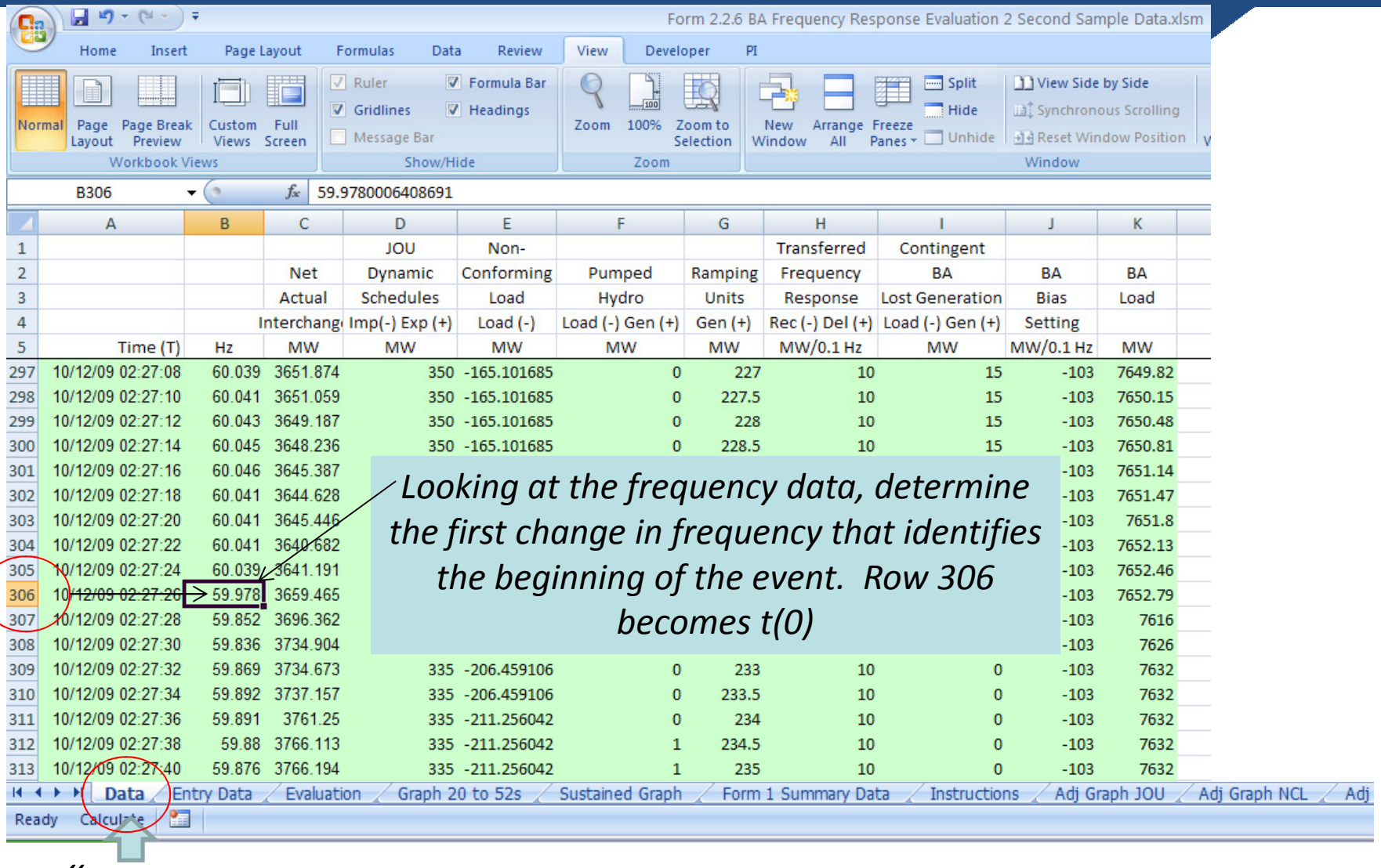
Frequency Diversity

- Frequency during the measurement periods of this standard is virtually the same across each Interconnection
  - If the BA's frequency data measures a significantly different deviation between the A Value and B Value than that in Form 1, it indicates that the data may be compressed or filtered

Form 2 Set-up for the Evaluation

- Find “t(0)” on Data worksheet
- Edit formula on Entry Data worksheet
  - Cell “C8”
- Find “event recovery time” on Data worksheet
- Edit formula on Entry Data worksheet
  - Cell “C11”

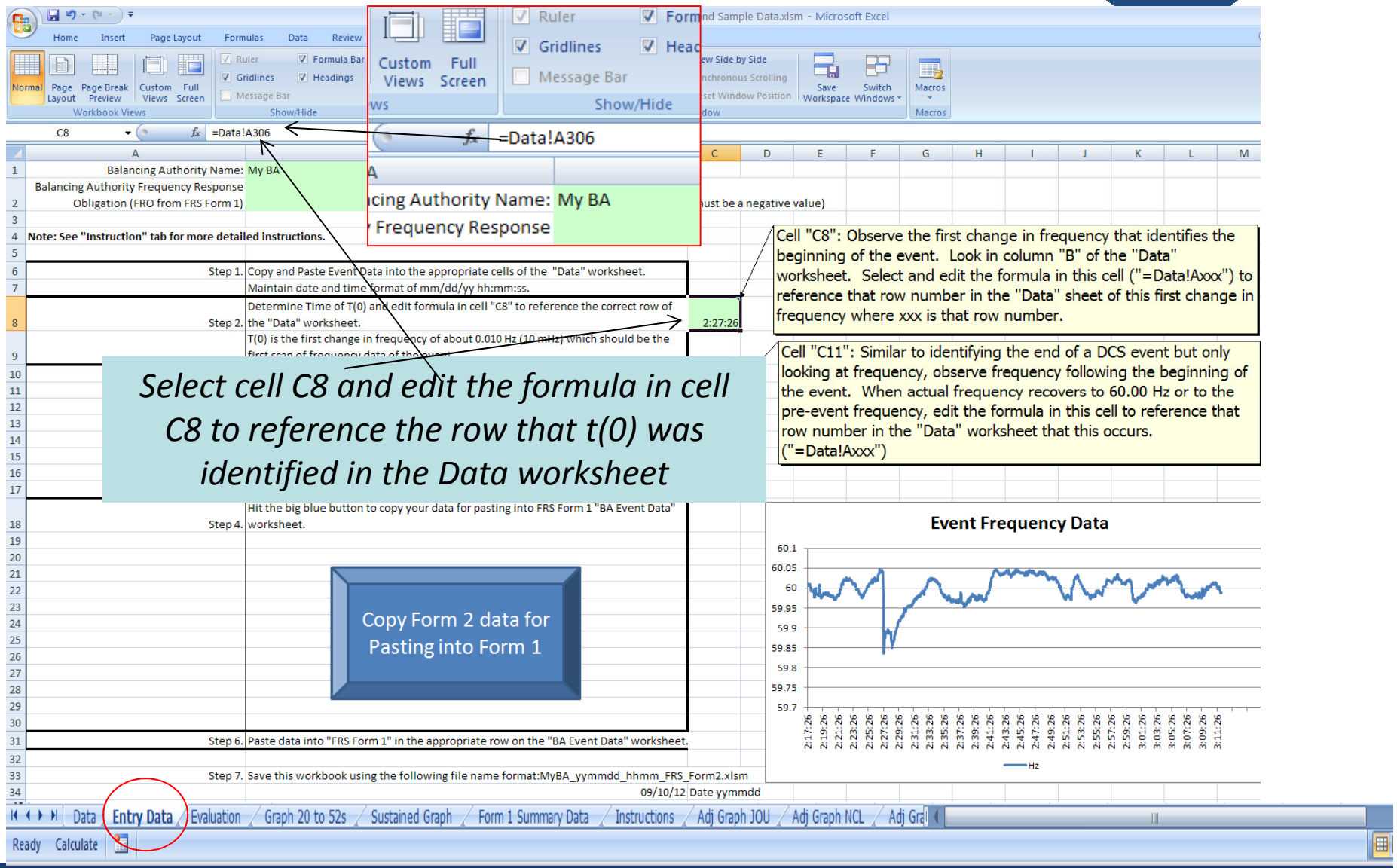
Identification of t(0) in Data



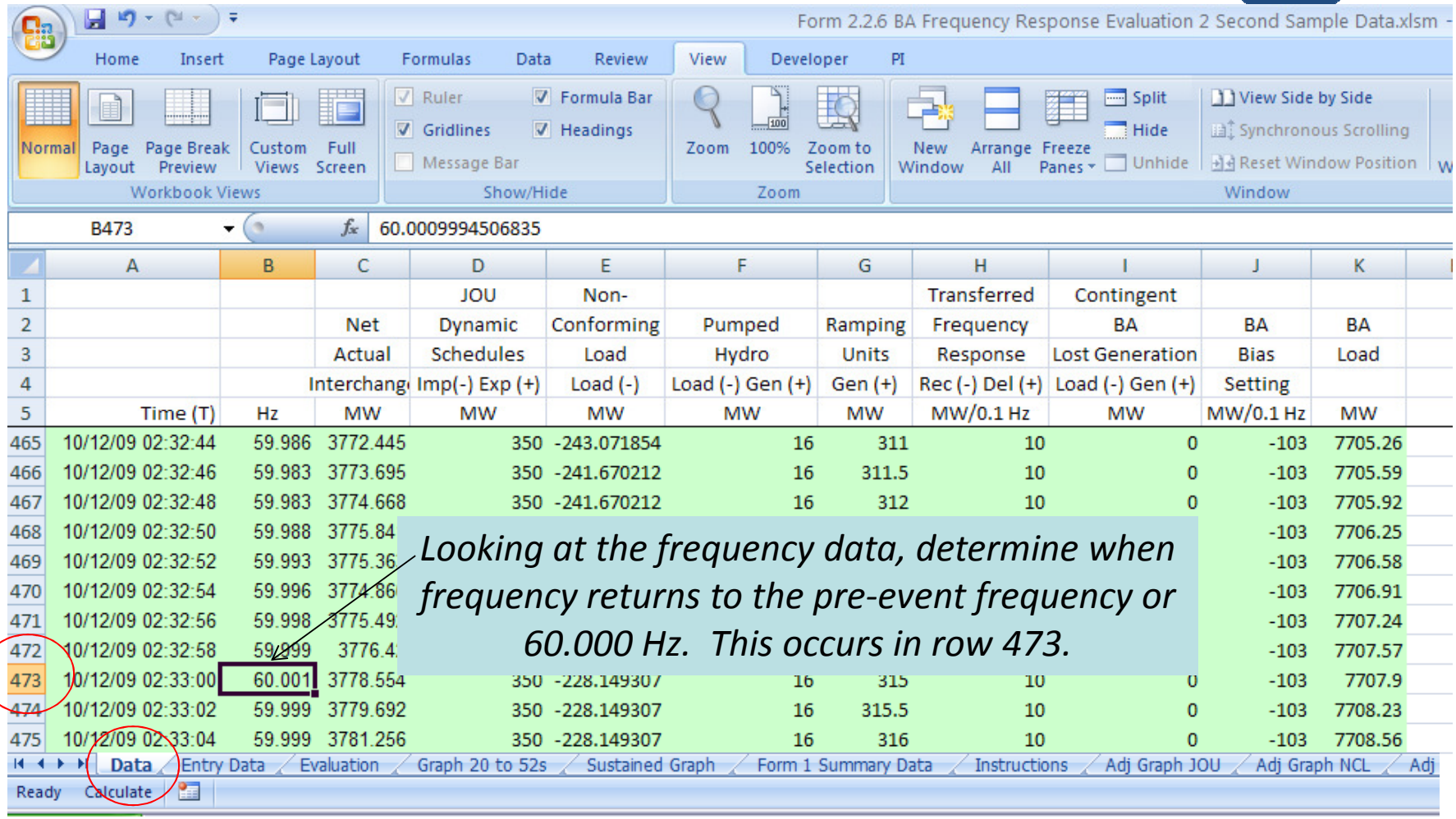
	A	B	C	D	E	F	G	H	I	J	K
1				JOU	Non-			Transferred	Contingent		
2			Net	Dynamic	Conforming	Pumped	Ramping	Frequency	BA	BA	BA
3			Actual	Schedules	Load	Hydro	Units	Response	Lost Generation	Bias	Load
4			Interchang	Imp(-) Exp (+)	Load (-)	Load (-) Gen (+)	Gen (+)	Rec (-) Del (+)	Load (-) Gen (+)	Setting	
5	Time (T)	Hz	MW	MW	MW	MW	MW	MW/0.1 Hz	MW	MW/0.1 Hz	MW
297	10/12/09 02:27:08	60.039	3651.874	350	-165.101685	0	227	10	15	-103	7649.82
298	10/12/09 02:27:10	60.041	3651.059	350	-165.101685	0	227.5	10	15	-103	7650.15
299	10/12/09 02:27:12	60.043	3649.187	350	-165.101685	0	228	10	15	-103	7650.48
300	10/12/09 02:27:14	60.045	3648.236	350	-165.101685	0	228.5	10	15	-103	7650.81
301	10/12/09 02:27:16	60.046	3645.387							-103	7651.14
302	10/12/09 02:27:18	60.041	3644.628							-103	7651.47
303	10/12/09 02:27:20	60.041	3645.446							-103	7651.8
304	10/12/09 02:27:22	60.041	3640.682							-103	7652.13
305	10/12/09 02:27:24	60.039	3641.191							-103	7652.46
306	10/12/09 02:27:26	59.978	3659.465							-103	7652.79
307	10/12/09 02:27:28	59.852	3696.362							-103	7616
308	10/12/09 02:27:30	59.836	3734.904							-103	7626
309	10/12/09 02:27:32	59.869	3734.673	335	-206.459106	0	233	10	0	-103	7632
310	10/12/09 02:27:34	59.892	3737.157	335	-206.459106	0	233.5	10	0	-103	7632
311	10/12/09 02:27:36	59.891	3761.25	335	-211.256042	0	234	10	0	-103	7632
312	10/12/09 02:27:38	59.88	3766.113	335	-211.256042	1	234.5	10	0	-103	7632
313	10/12/09 02:27:40	59.876	3766.194	335	-211.256042	1	235	10	0	-103	7632

"Data" Tab: BA Event scan rate data placed in specific columns

Entry Data Worksheet Setup

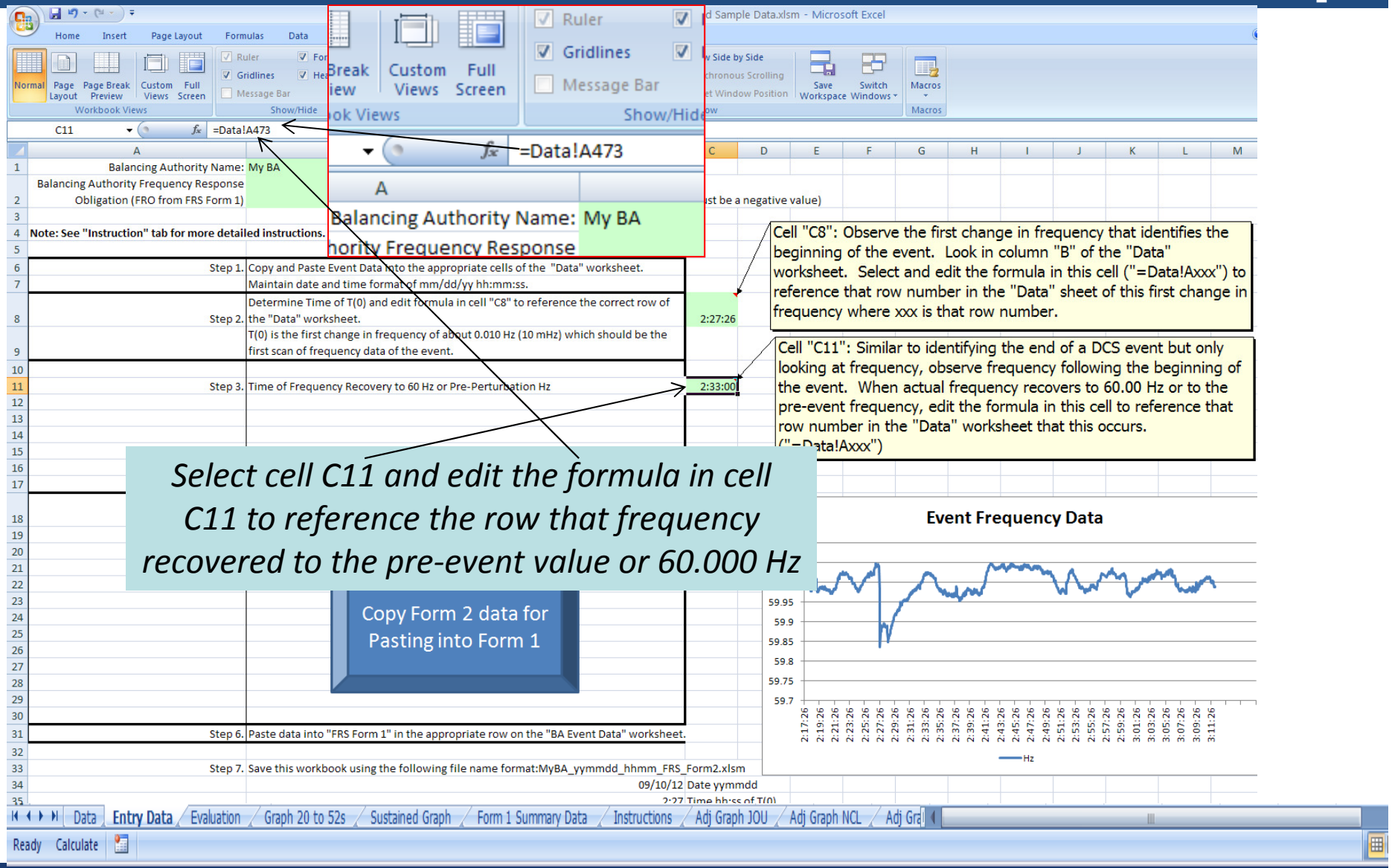


Determine Event Recovery Time



	A	B	C	D	E	F	G	H	I	J	K
1				JOU	Non-			Transferred	Contingent		
2			Net	Dynamic	Conforming	Pumped	Ramping	Frequency	BA	BA	BA
3			Actual	Schedules	Load	Hydro	Units	Response	Lost Generation	Bias	Load
4			Interchang	Imp(-) Exp (+)	Load (-)	Load (-) Gen (+)	Gen (+)	Rec (-) Del (+)	Load (-) Gen (+)	Setting	
5	Time (T)	Hz	MW	MW	MW	MW	MW	MW/0.1 Hz	MW	MW/0.1 Hz	MW
465	10/12/09 02:32:44	59.986	3772.445	350	-243.071854	16	311	10	0	-103	7705.26
466	10/12/09 02:32:46	59.983	3773.695	350	-241.670212	16	311.5	10	0	-103	7705.59
467	10/12/09 02:32:48	59.983	3774.668	350	-241.670212	16	312	10	0	-103	7705.92
468	10/12/09 02:32:50	59.988	3775.84							-103	7706.25
469	10/12/09 02:32:52	59.993	3775.36							-103	7706.58
470	10/12/09 02:32:54	59.996	3774.86							-103	7706.91
471	10/12/09 02:32:56	59.998	3775.49							-103	7707.24
472	10/12/09 02:32:58	59.999	3776.4							-103	7707.57
473	10/12/09 02:33:00	60.001	3778.554		350 -228.149307	16	315	10	0	-103	7707.9
474	10/12/09 02:33:02	59.999	3779.692	350	-228.149307	16	315.5	10	0	-103	7708.23
475	10/12/09 02:33:04	59.999	3781.256	350	-228.149307	16	316	10	0	-103	7708.56

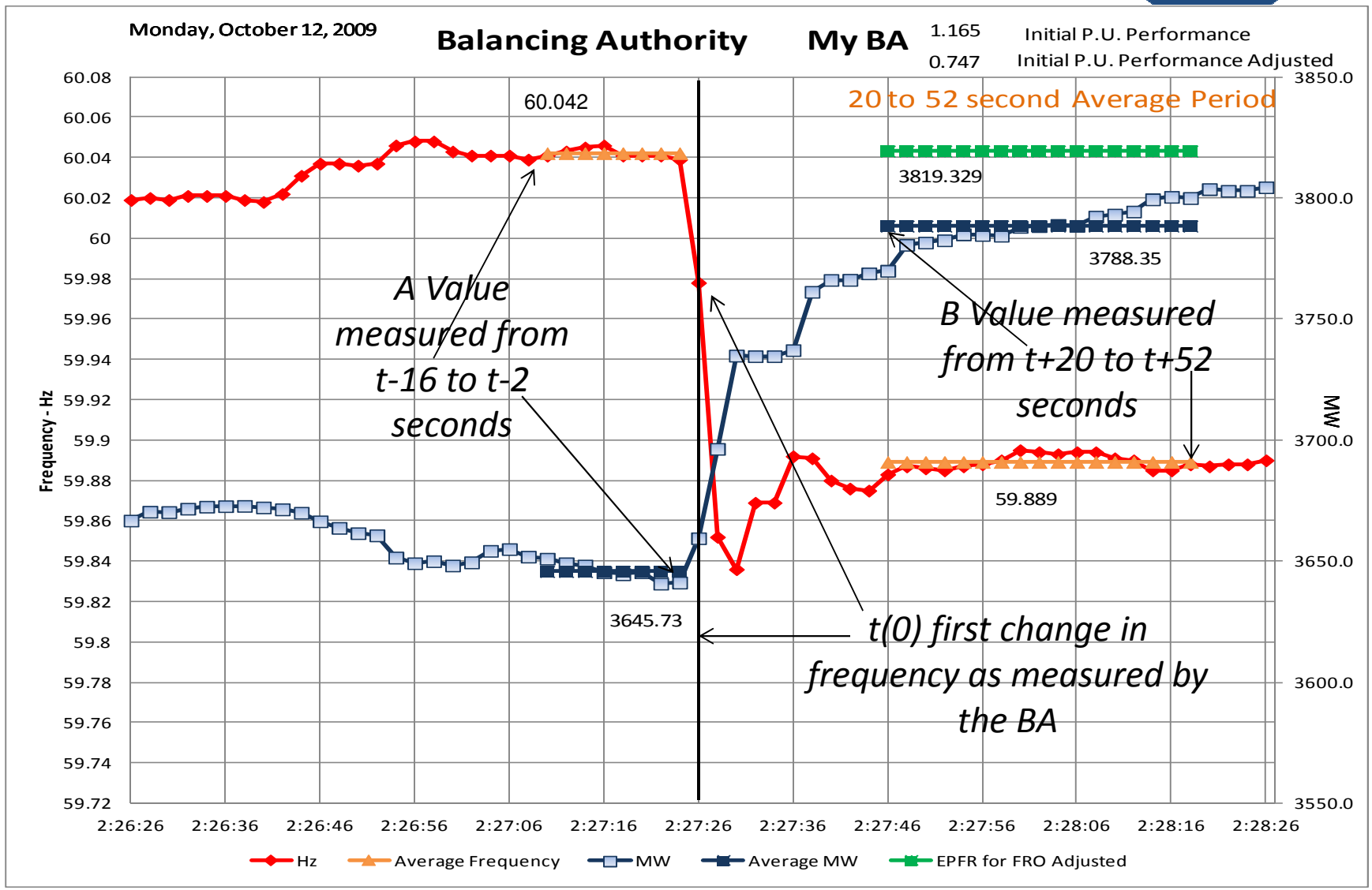
Entry Data Worksheet Final Step



Lessons Learned – Setting t(0)

- Many BAs set t(0) one cell late
  - Properly set, the first change in frequency will be in the exact center of the Graph on the “Graph 20 to 52s” worksheet
  - The best performance measure will be assured if the A Value average period data does not contain a data point of the event, frequency or NAI
  - Setting t(0) late can cause the Frequency Response measure to be low due to Frequency Response still increasing and/or B Value frequency measuring too low

Form 2 Frequency Graph



Data Worksheet Details

Critical Data: Time, frequency and NAI

Important Data: Transferred Frequency Response, Contingent BA Loss, Bias Setting and BA Load

			JOU	Non-			Transferred	Contingent		
		Net	Dynamic	Conforming	Pumped	Ramping	Frequency	BA	BA	BA
		Actual	Schedules	Load	Hydro	Units	Response	Lost Generation	Bias	Load
		Interchange	Imp(-) Exp (+)	Load (-)	Load (-) Gen (+)	Gen (+)	Rec (-) Del (+)	Load (-) Gen (+)	Setting	
Time (T)	Hz	MW	MW	MW	MW	MW	MW/0.1 Hz	MW	MW/0.1 Hz	MW
10/12/09 02:12:00	59.981	3669.878418	350	351.361511	0	0	10	15	-103	7500
10/12/09 02:12:04	59.981	3671.699707	350	351.361511	0	0.5	10	15	-103	7500.33
10/12/09 02:12:08	59.98	3671.698486	350	351.361511	0	1	10	15	-103	7500.66

Optional Data: Adjustments – JOU, Non-conforming load, Pumped Hydro, Ramping Units

DO NOT delete columns for any optional data not utilized or any non-applicable data for Transferred Frequency Response, Contingent BA Loss or Load,. Leave data as zero or blank.

Data Sign Convention

- Net Actual Interchange +/-
- Joint Owned Unit
  - Import (-) Export (+)
- Non-Conforming Load (-)
  - Option on Evaluation worksheet to flip sign to positive in cell “Z1”. Enter “+” if your load data is positive. Enter “-” if your load data is negative
- Pumped-Hydro
  - Load (-) Gen (+)
- Ramping Units Gen (+)

Sign Convention – Part 2

- Transferred Frequency Response
  - Receiving BA Rec (-)
  - Delivering BA Del (+)
  - Interconnection Transferred Frequency Response should net to zero
- Contingent BA
  - Lost Load (-)
  - Lost Generation (+)
- BA Bias Setting (-)
- BA Load (+)

Pasting Data into Worksheet

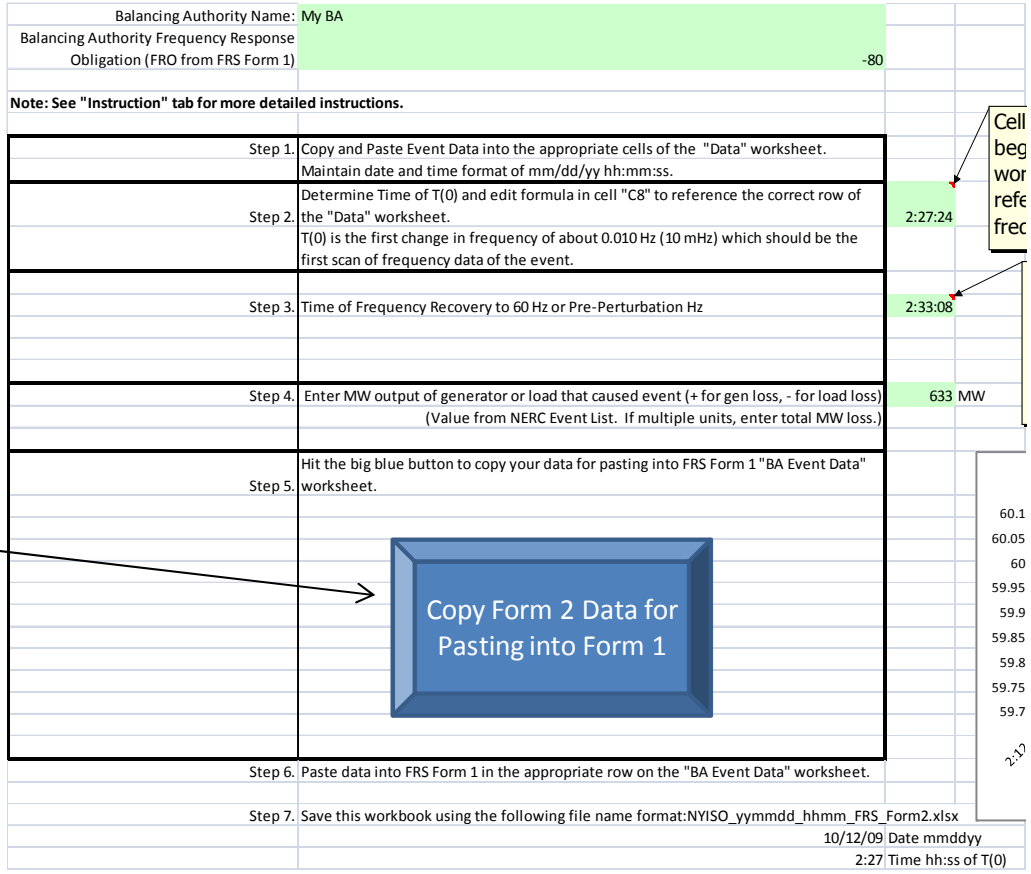
- Historian data collection formulas should be removed from Form 2 before submitting. Use PasteSpecial/Values to strip formulas and only paste data values into the Data worksheet.
- Do not delete any data columns.
- Provide a minimum of 5 minutes of data before the beginning of the event and a minimum of 15 minutes of data after the event. The spreadsheet will easily accommodate 60 minutes of data.

Evaluation Complete

- Execution is now complete.
  - Performance of your BA for all the average periods in the field trial is ready to be copied into FRS Form 1.
  - Perform a mouse click on the “Copy Form 2 Data for Pasting into Form 1” macro on the “Entry Data” worksheet. The correct data is now copied.

Form 2 Data Copy Button

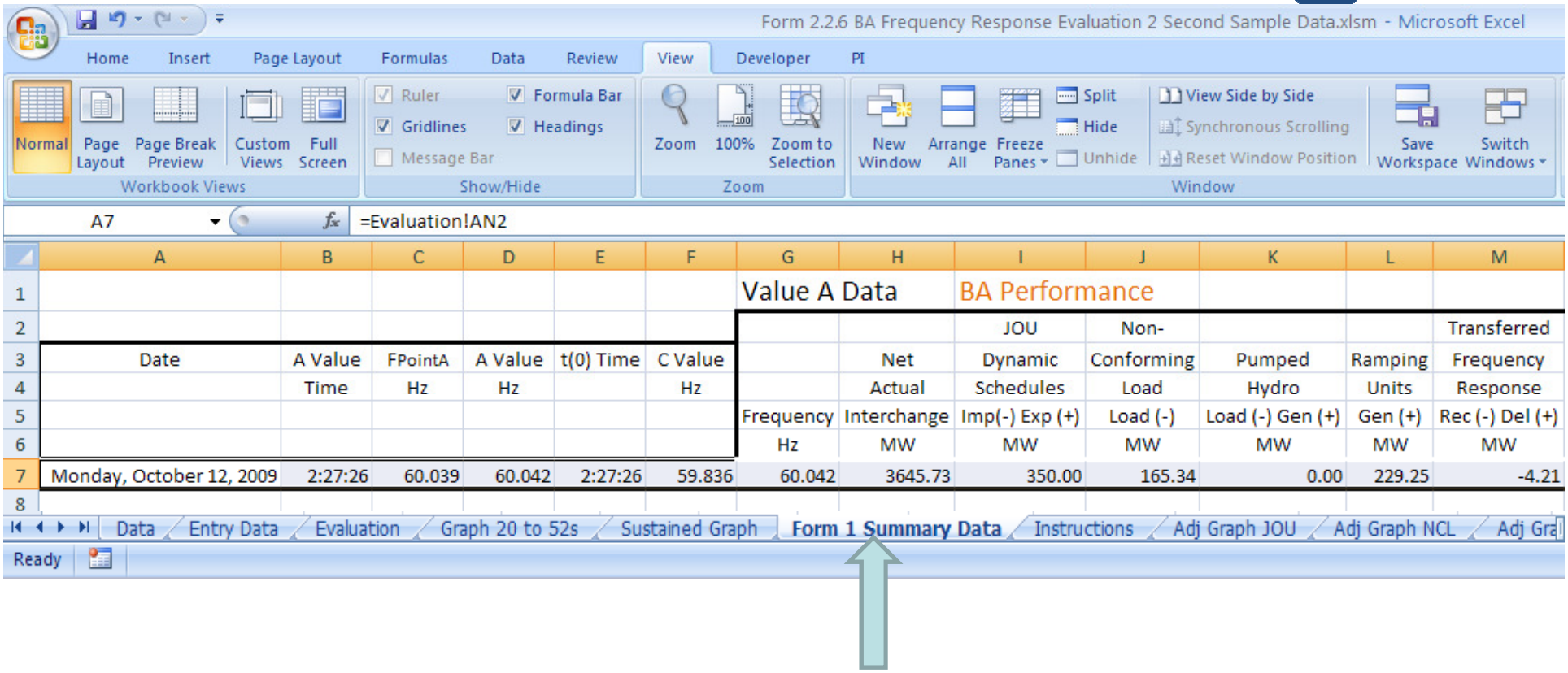
Copy Button on Entry Data worksheet



Alternate Copy without Macro

- If you prefer not to enable macros
  - Navigate to the “Form 1 Summary Data” worksheet
  - Select cells “A7 through AE7”
  - Select copy
  - PasteSpecial/Values into FRS Form 1 on the appropriate event row

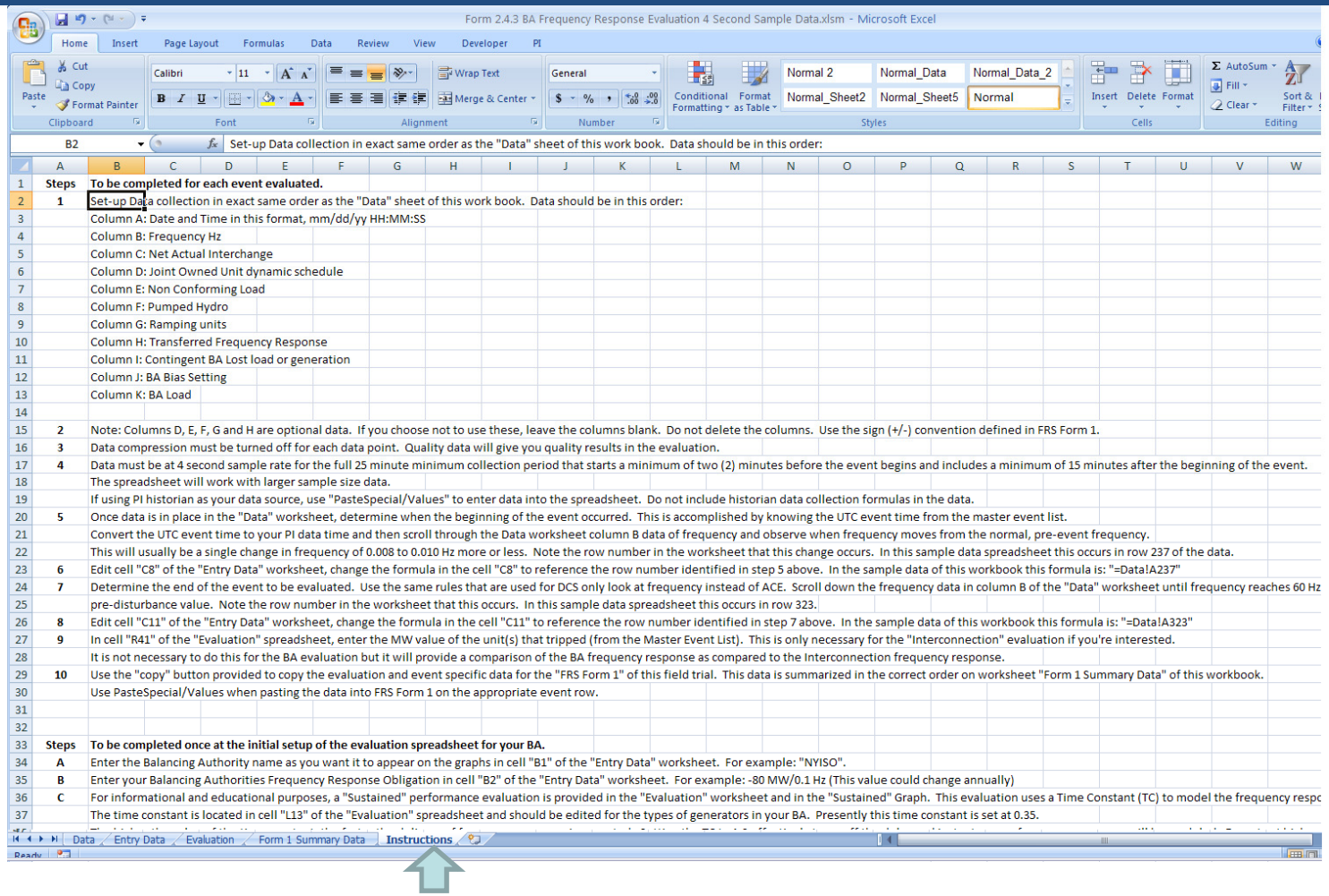
Location of Data for Form 1



"Form 1 Summary Data" Tab: This single event data and performance results needed for FRS Form 1 is contained in row 7, columns A through AE

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Detail Instructions



	A	B
1	**Steps**	**To be completed for each event evaluated.**
2	**1**	Set-up Data collection in exact same order as the "Data" sheet of this work book. Data should be in this order:
3		Column A: Date and Time in this format, mm/dd/yy HH:MM:SS
4		Column B: Frequency Hz
5		Column C: Net Actual Interchange
6		Column D: Joint Owned Unit dynamic schedule
7		Column E: Non Conforming Load
8		Column F: Pumped Hydro
9		Column G: Ramping units
10		Column H: Transferred Frequency Response
11		Column I: Contingent BA Lost load or generation
12		Column J: BA Bias Setting
13		Column K: BA Load
14		
15	**2**	Note: Columns D, E, F, G and H are optional data. If you choose not to use these, leave the columns blank. Do not delete the columns. Use the sign (+/-) convention defined in FRS Form 1.
16	**3**	Data compression must be turned off for each data point. Quality data will give you quality results in the evaluation.
17	**4**	Data must be at 4 second sample rate for the full 25 minute minimum collection period that starts a minimum of two (2) minutes before the event begins and includes a minimum of 15 minutes after the beginning of the event.
18		The spreadsheet will work with larger sample size data.
19		If using PI historian as your data source, use "PasteSpecial/Values" to enter data into the spreadsheet. Do not include historian data collection formulas in the data.
20	**5**	Once data is in place in the "Data" worksheet, determine when the beginning of the event occurred. This is accomplished by knowing the UTC event time from the master event list.
21		Convert the UTC event time to your PI data time and then scroll through the Data worksheet column B data of frequency and observe when frequency moves from the normal, pre-event frequency.
22		This will usually be a single change in frequency of 0.008 to 0.010 Hz more or less. Note the row number in the worksheet that this change occurs. In this sample data spreadsheet this occurs in row 237 of the data.
23	**6**	Edit cell "C8" of the "Entry Data" worksheet, change the formula in the cell "C8" to reference the row number identified in step 5 above. In the sample data of this workbook this formula is: "=Data!A237"
24	**7**	Determine the end of the event to be evaluated. Use the same rules that are used for DCS only look at frequency instead of ACE. Scroll down the frequency data in column B of the "Data" worksheet until frequency reaches 60 Hz
25		pre-disturbance value. Note the row number in the worksheet that this occurs. In this sample data spreadsheet this occurs in row 323.
26	**8**	Edit cell "C11" of the "Entry Data" worksheet, change the formula in the cell "C11" to reference the row number identified in step 7 above. In the sample data of this workbook this formula is: "=Data!A323"
27	**9**	In cell "R41" of the "Evaluation" spreadsheet, enter the MW value of the unit(s) that tripped (from the Master Event List). This is only necessary for the "Interconnection" evaluation if you're interested.
28		It is not necessary to do this for the BA evaluation but it will provide a comparison of the BA frequency response as compared to the Interconnection frequency response.
29	**10**	Use the "copy" button provided to copy the evaluation and event specific data for the "FRS Form 1" of this field trial. This data is summarized in the correct order on worksheet "Form 1 Summary Data" of this workbook.
30		Use PasteSpecial/Values when pasting the data into FRS Form 1 on the appropriate event row.
31		
32		
33	**Steps**	**To be completed once at the initial setup of the evaluation spreadsheet for your BA.**
34	**A**	Enter the Balancing Authority name as you want it to appear on the graphs in cell "B1" of the "Entry Data" worksheet. For example: "NYISO".
35	**B**	Enter your Balancing Authorities Frequency Response Obligation in cell "B2" of the "Entry Data" worksheet. For example: -80 MW/0.1 Hz (This value could change annually)
36	**C**	For informational and educational purposes, a "Sustained" performance evaluation is provided in the "Evaluation" worksheet and in the "Sustained" Graph. This evaluation uses a Time Constant (TC) to model the frequency respc
37		The time constant is located in cell "L13" of the "Evaluation" spreadsheet and should be edited for the types of generators in your BA. Presently this time constant is set at 0.35.

"Instructions" Tab: Detailed instructions for each step of the process

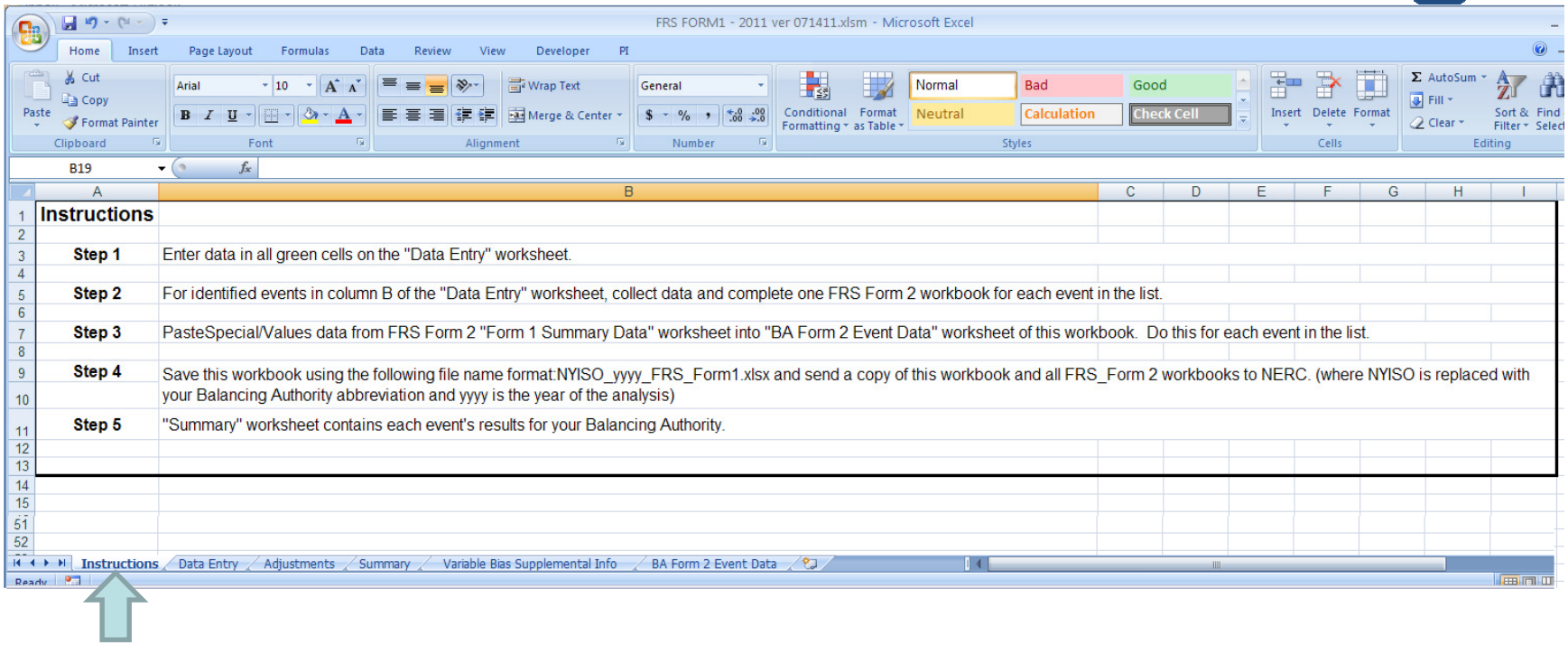
FRS Form 2 File Naming Convention

- Use the following file name convention:
  - Xxxxx_yymmdd_hhmm_FRS_Form2.xlsm
    - Where xxxxx is your BA mnemonic
    - yy is year
    - mm is month
    - dd is day
    - hh is hour
    - mm is minute

FRS Form 1

- One FRS Form 1 for each Interconnection will be generated and posted by NERC
- Contains list of events: date and time that each BA in that Interconnection must measure performance by completing a FRS Form 2
- As each FRS Form 2 is completed, the resulting BA performance data is added to FRS Form 1 by using the PasteSpecial/Values action
- Each BA creates a FRS Form 1 with the performance of their BA to each event

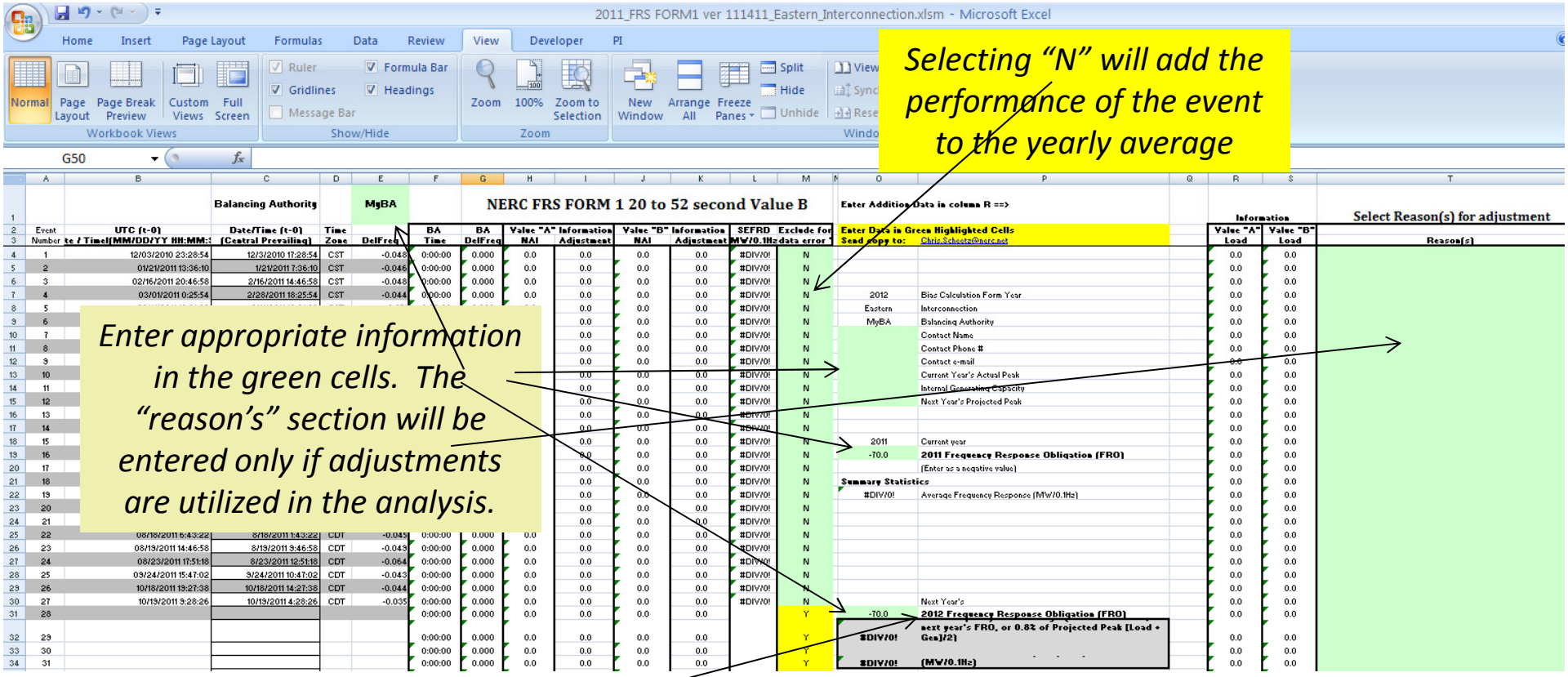
FRS Form 1 Instructions



"Instructions" Tab: Basic instructions for completing FRS Form 1

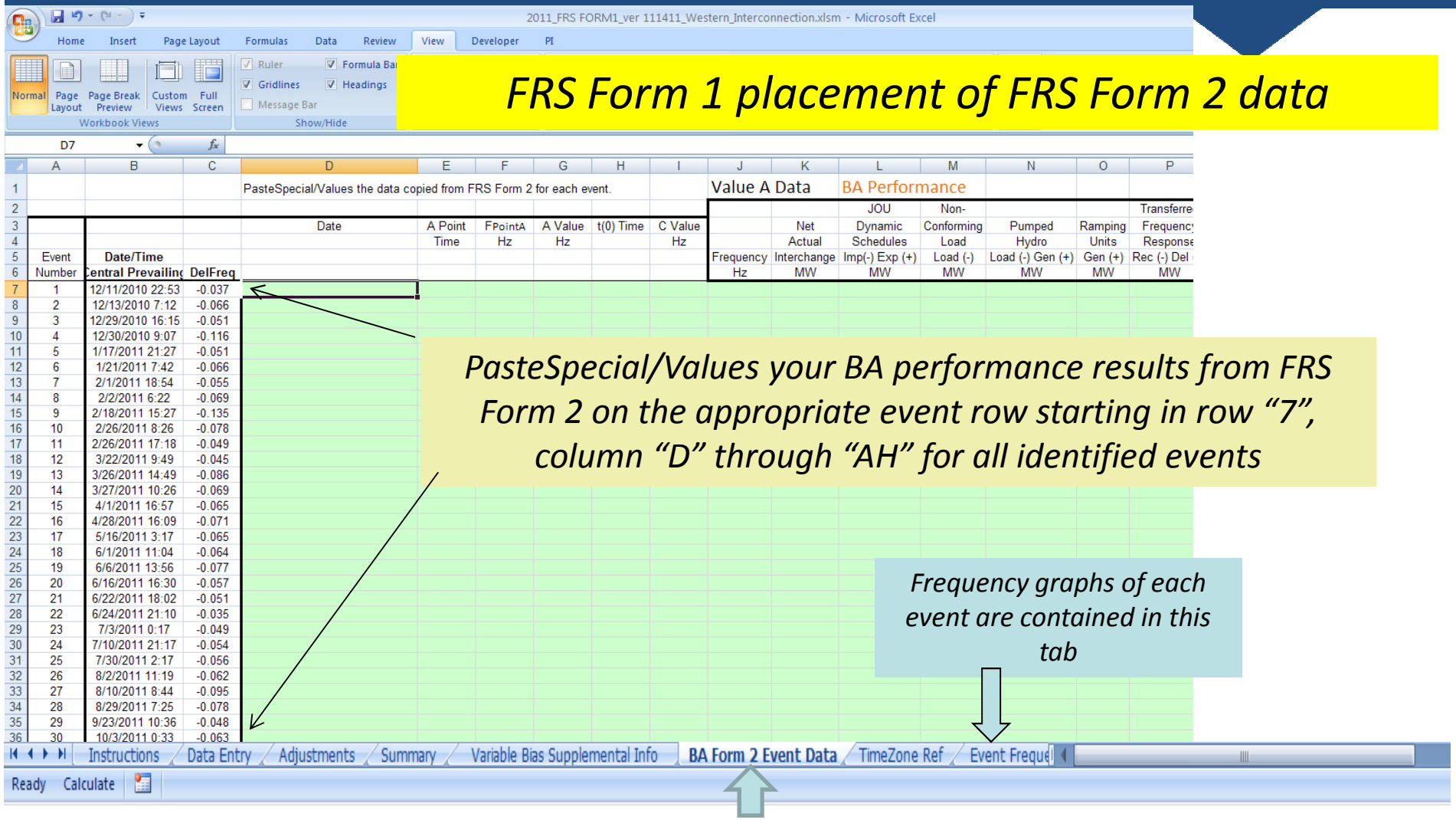
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

FRS Form 1 Data Entry Worksheet



Correct "year" information will automatically update when the 24th frequency event is identified by NERC and added to the Event Date/Time column

BA Form 2 Event Data



FRS Form 1 placement of FRS Form 2 data

PasteSpecial/Values your BA performance results from FRS Form 2 on the appropriate event row starting in row "7", column "D" through "AH" for all identified events

Frequency graphs of each event are contained in this tab

"BA Form 2 Event Data" Tab: The BA will enter the performance data from FRS Form 2 in this section

FRS Form 1 File Naming Convention

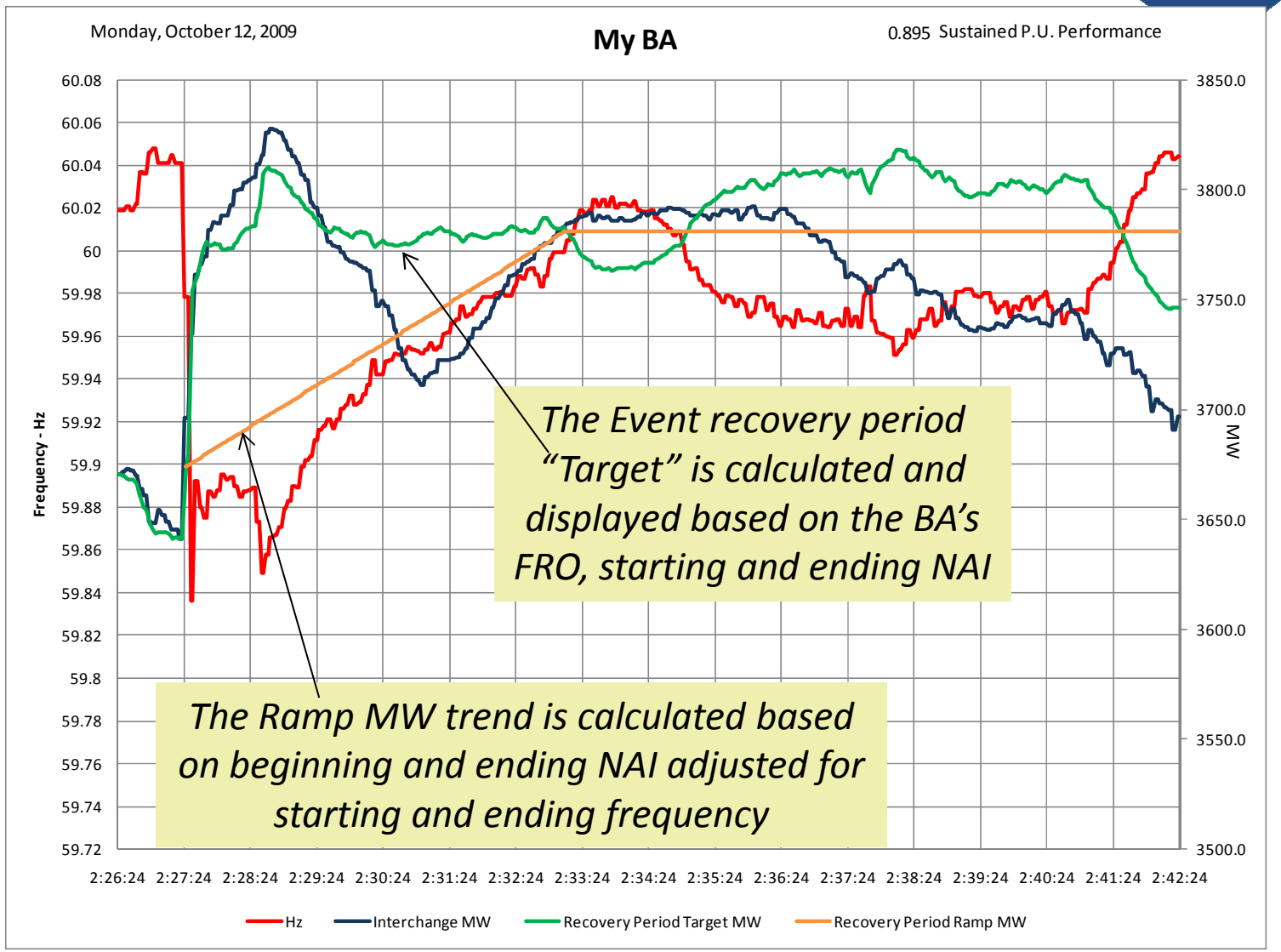
- Use the following file name convention.
  - Xxxxx_yyyy_FRS_Form1.xlsm
    - Where xxxxx is your BA pneumonic
    - yyyy is year

Graphs

- Additional Graphs
  - Graphs of BA Initial performance as measured in the field trial
  - Graphs of BA Sustained Frequency Response performance as a function of the FRO
    - Per Unit evaluation (P.U.) is used for this measure where 1.0 P.U. represents that the BA delivered exactly its FRO during the measurement period
  - Graphs of BA Adjustments are available if the BA utilized this functionality

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BA Sustained Measure



FRS Form 1 and 2 New Versions

- FRS Form 2 revised with new version number (6)
  - Use appropriate AGC Scan rate form
  - Re-build previously evaluated events using this new version
    - Copy/PasteSpecial old data from previous Form 2 into new version
      - No change to the Data sheet layout
    - Set t(0) and Event Recovery time
    - Copy data into new Form 1
  - Some events on the original Form 1 are not in the new Form 1 version
    - Removed due to issues identified earlier
    - Replacement events added

Contact Information

- If you have questions related to the data request, contact:
  - Questions concerning FRS Form 1 and FRS Form 2
    - Sydney Niemeyer
      - (T) 713.537.3715
      - (E) sydney.niemeyer@nrgenergy.com
  - Questions concerning the standard and associated documents
    - Darrel Richardson
      - (T) 609.613.1848
      - (E) darrel.richardson@nerc.net

BAL-003-1 Information

- Standard posted for formal comment from October 25, 2011 through December 8, 2011
- Standard posted for Industry Ballot from November 29, 2011 through December 8, 2011
- Link to BAL-003-1 Frequency Response and Frequency Bias Setting Standard Website
  - http://www.nerc.com/filez/standards/Frequency_Response.html

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Questions?

- Please submit your questions via the chat feature in ReadyTalk
- The presenters will respond to as many questions as possible during remainder of the scheduled webinar
- The webinar presentation and slides will be posted to the NERC website

October 2011 Snowstorm

November 18, 2011 Participants Committee

Overview

- On Saturday October, 29 and continuing into Sunday October 30, New England experienced a “Rare and Historic October Nor’easter”
- Significant portions of the utility system were damaged due to heavy wet snow on trees that had an unusual amount of foliage for this time of year
- The bulk electric system was operated to meet reliability criteria by the ISO and LCC system operators
- Implementation of an Abnormal Conditions Alert started on Saturday October 29, and continued until Monday November 7, 2011
- Minimum Generation Emergencies occurred two times during the event

© 2011 ISO New England Inc.

Historical Perspective: Atypical Weather

- The typical leaf drop in southern New England is high by the end of October. In nine of the past twelve years the leaf drop across southern NE has been high to nearly complete by October's end. The 2010 leaf drop is the representative of a normal autumn season.

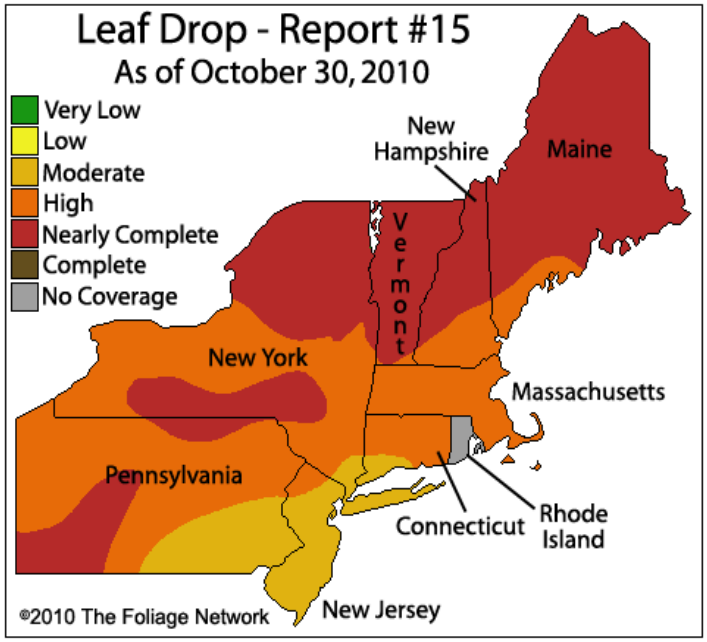


Figure 1

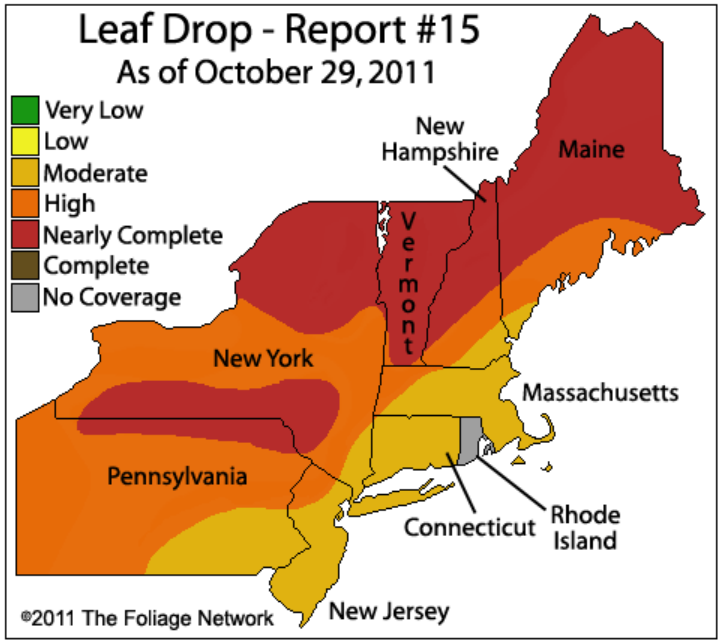


Figure 2

- The 2011 late October leaf drop was only moderate across southern New England. This was due to above normal rainfall and the lack of cold temperatures in the months preceding the storm. This caused the foliage to change later and to be held longer.

© 2011 ISO New England Inc.

National Weather Service Taunton, MA Event Review

"Rare and Historic October Nor'easter"

- 1 to 2 feet of wet heavy snow across southern New England.
  - Snowfall rates were 3" per hour sustained for several hours.
- Widespread tree damage and downed limbs resulted in power outages across CT, MA and southern NH.
- Damage to electric delivery infrastructure was widespread

© 2011 ISO New England Inc.

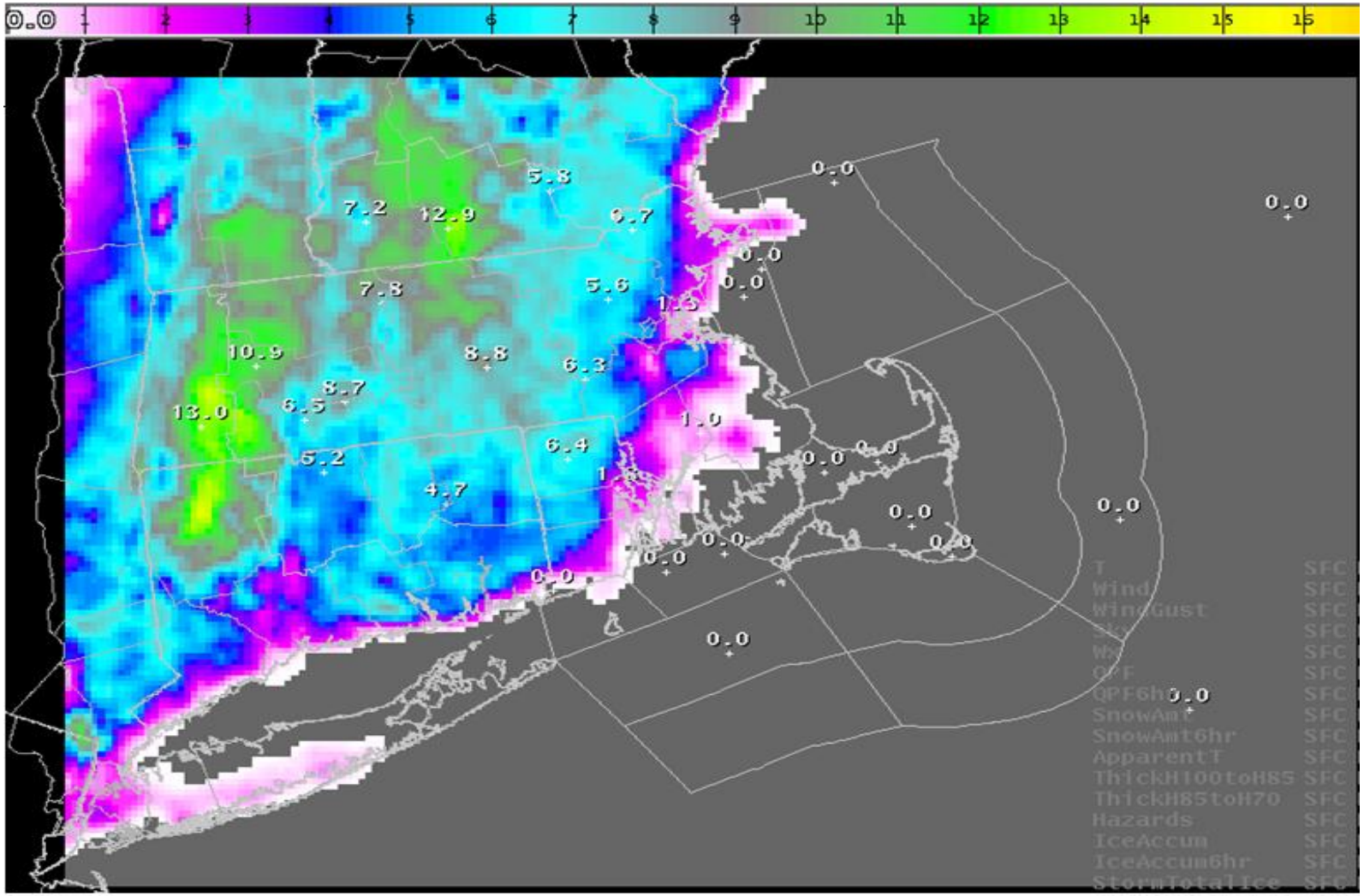
October Snowstorms

- October 9, 1804 (Wikipedia)
  - 6” in Connecticut Valley, 24-36” northern and western areas.
  - Widespread damage to orchards
- October 4, 1987 (www.erh.noaa.gov)
  - 6” in Albany NY, 20+” Catskills to Western Berkshires
  - Several hundred thousand without power
    - Some as long as 14 days
- October 29, 2011 (NWS Taunton, Ma)
  - 12+” across CT, MA and southern NH,
  - Extensive and widespread damage to electric delivery network across southern New England
    - Transmission + Distribution circuits impacted

© 2011 ISO New England Inc.

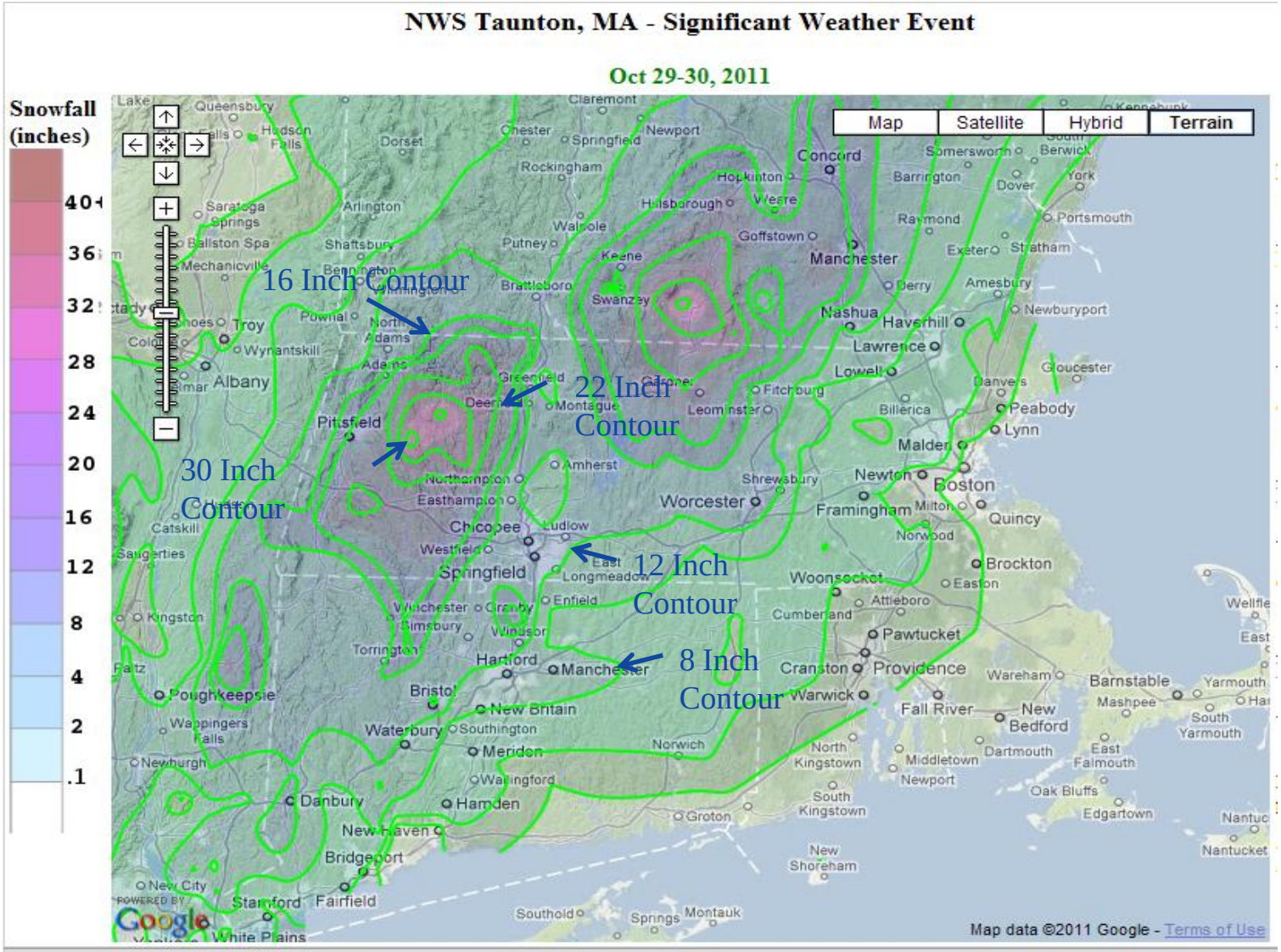
Weather and Load Forecast vs. Actual

Forecast Snow Fall Amounts
October 28, 2011 15:15



© 2011 ISO New England Inc.

Actual Snow Fall Amounts



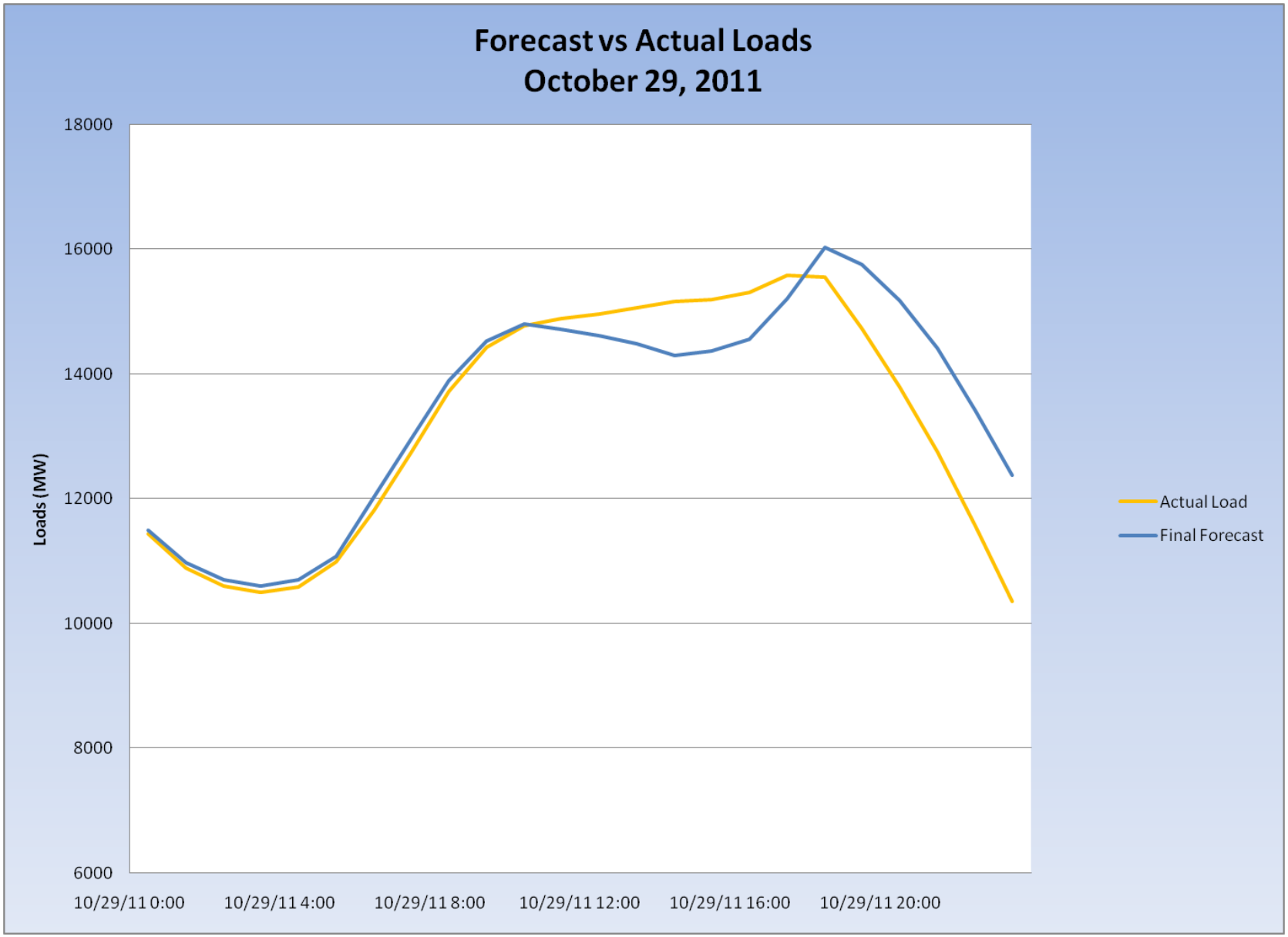
© 2011 ISO New England Inc.

Load Forecasting on October 29

- Actual loads show people stayed home, and loads increased throughout the afternoon due to increased lighting load.

- Evening peak was close to forecast, followed closely by loss of customer load

© 2011 ISO New England Inc.

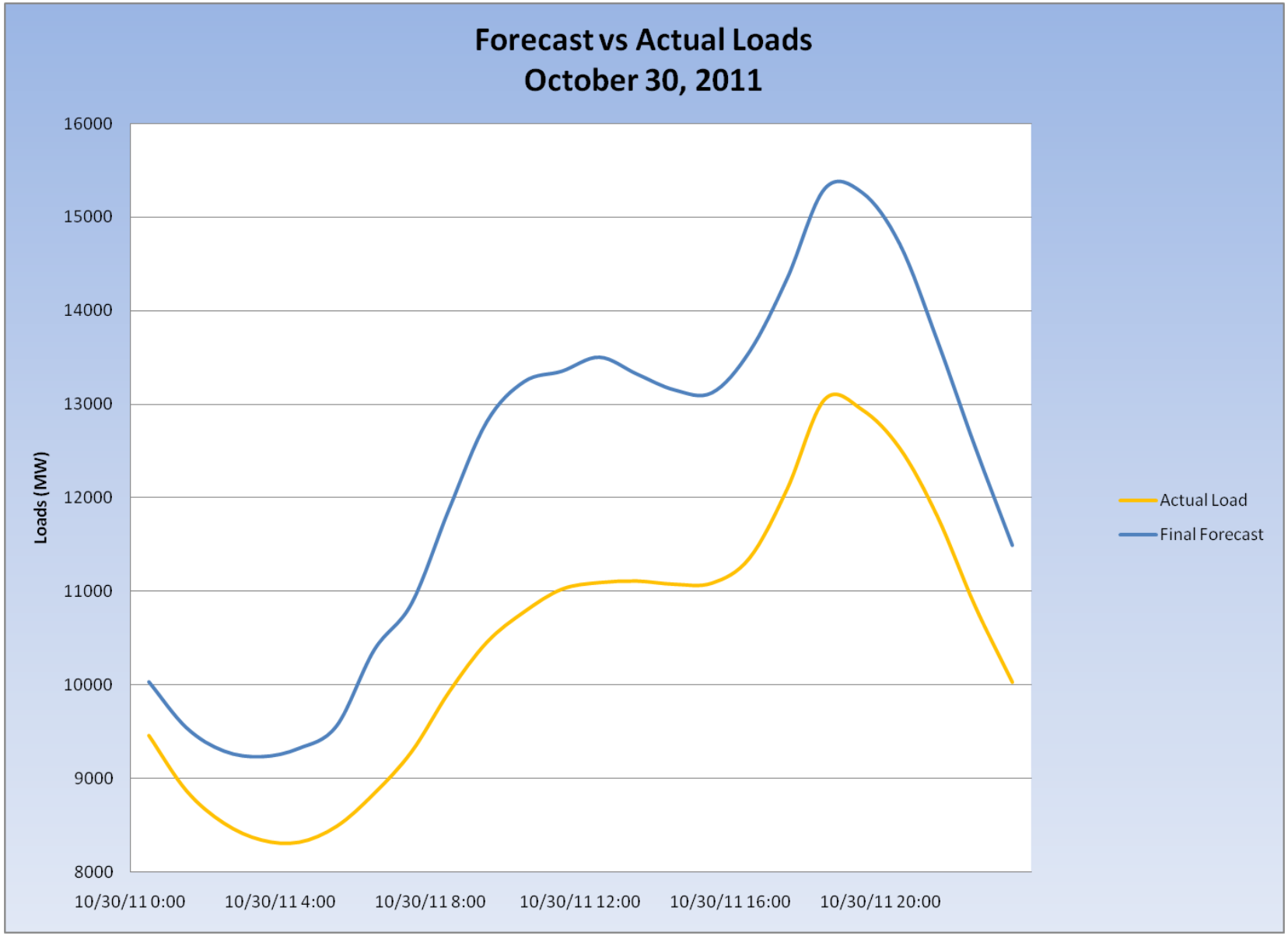


© 2011 ISO New England Inc.

Load Forecasting on October 30

- Performed Saturday morning by 10:00
- Recognized that storm was coming, but did not include load loss due to no historical reference for this type of fall storm
- Actual loads were considerably lower due to the large loss of load

© 2011 ISO New England Inc.

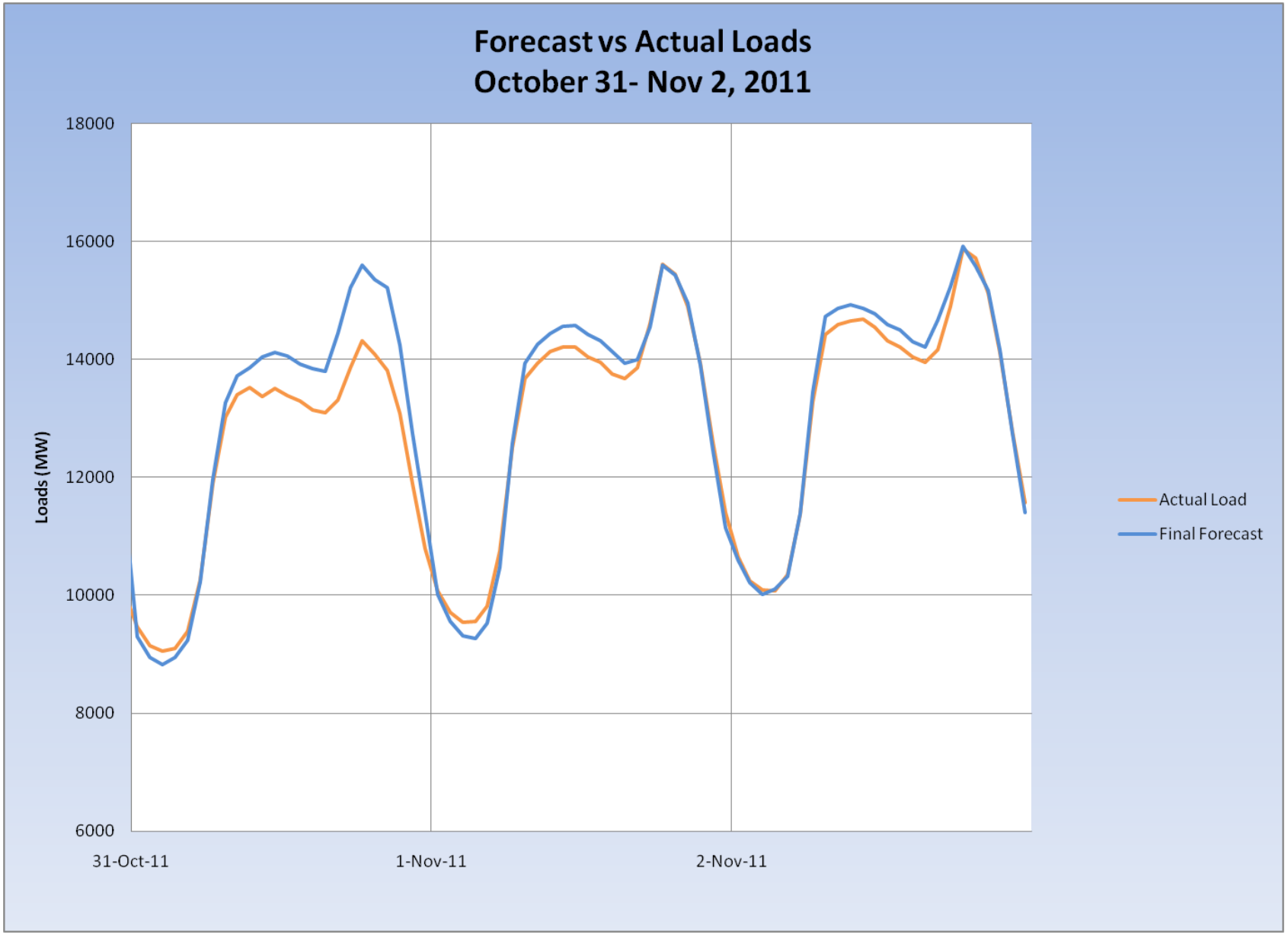


© 2011 ISO New England Inc.

Load Forecasting for October 31 – November 2

- Forecasters factored in the amount of customers that were out of service

© 2011 ISO New England Inc.



© 2011 ISO New England Inc.

Capacity Assessment and Generation

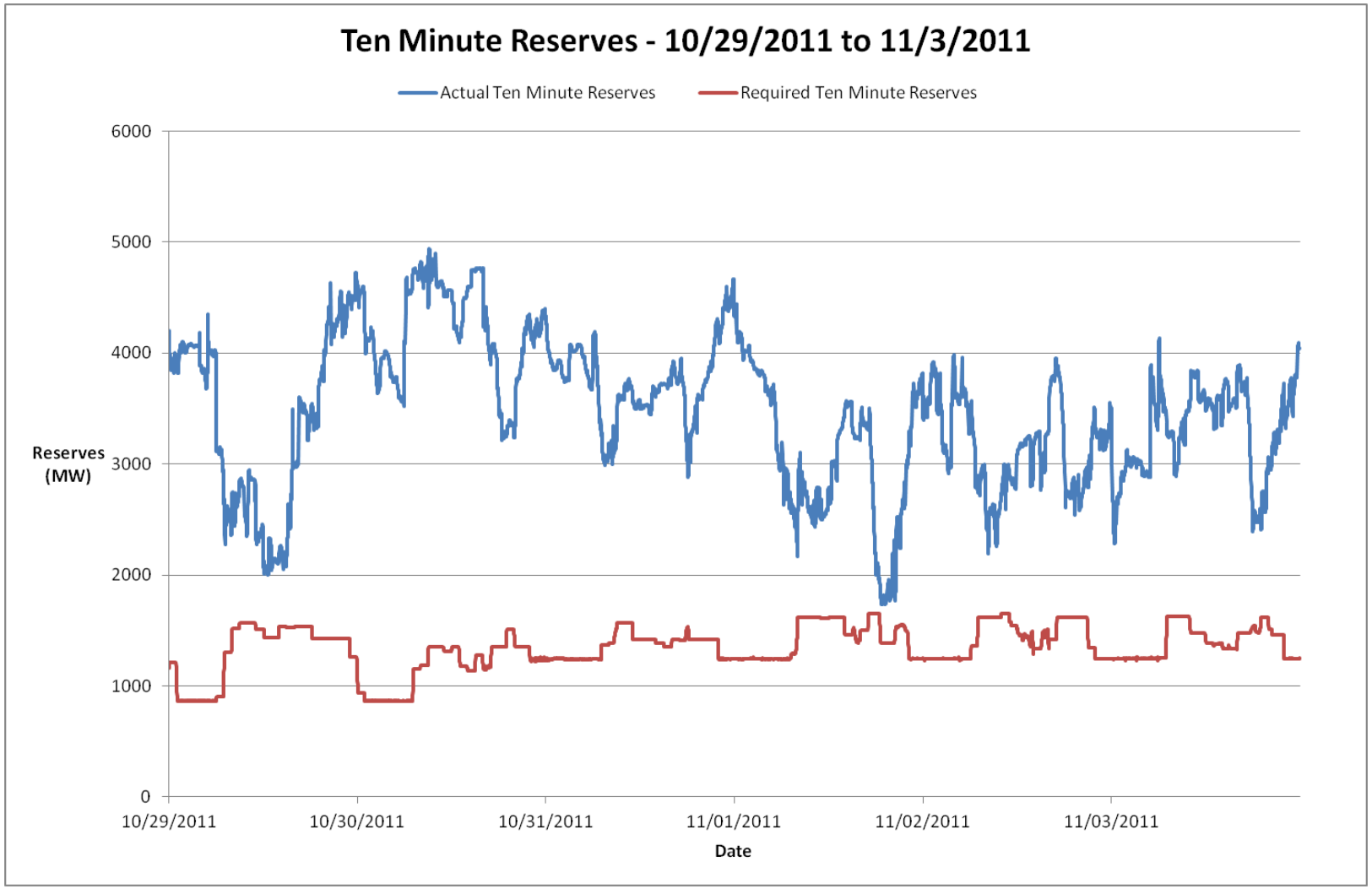
Operating and Ten Minute Reserves

- Ten Minute Reserves
  - **Requirement** is 100% of the largest single source in New England
    - Varied from 865 MW to 1656 MW during this event
  - **Actual** is the amount of generation that is available in ten minutes

- Operating Reserves
  - **Requirement** is 50% of second largest single source in New England PLUS the Ten Minute Reserve Requirement
    - Varied from 1203 MW to 2436 MW during this event
  - **Actual** is the amount of generation that is available in thirty minutes

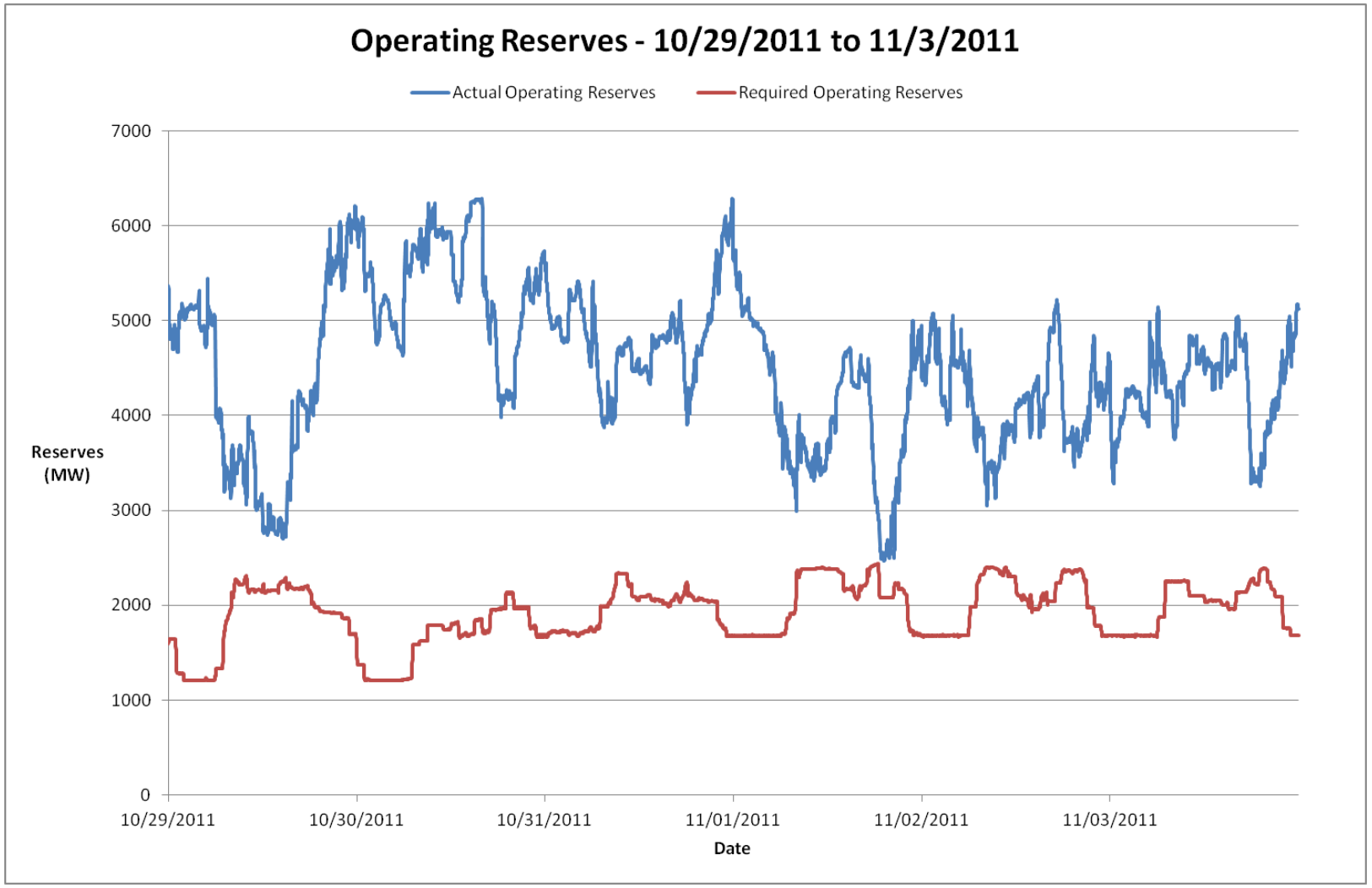
© 2011 ISO New England Inc.

Ten Minute Reserves



© 2011 ISO New England Inc.

Operating Reserves



© 2011 ISO New England Inc.

Minimum Generation Emergency

Date / Time	Event
10/29 23:30	Warning until 09:00
10/30 02:00	Declared
10/30 06:30	Cancelled
10/30 09:00	Extended Warning to 17:00
10/30 16:00	Declared
10/30 18:00	Cancelled
10/30 18:00	Warning Cancelled
10/31 00:00	Warning until 07:00

© 2011 ISO New England Inc.

Storm Related Generation Outages & Reductions

- There were approximately 1500 MW of generator reductions and outages
  - Most significant outages and reductions were resolved by 0900 on 10/31, with the exception of one generator which remained Out of Service due to transmission restrictions until 11/02.

© 2011 ISO New England Inc.

Transmission

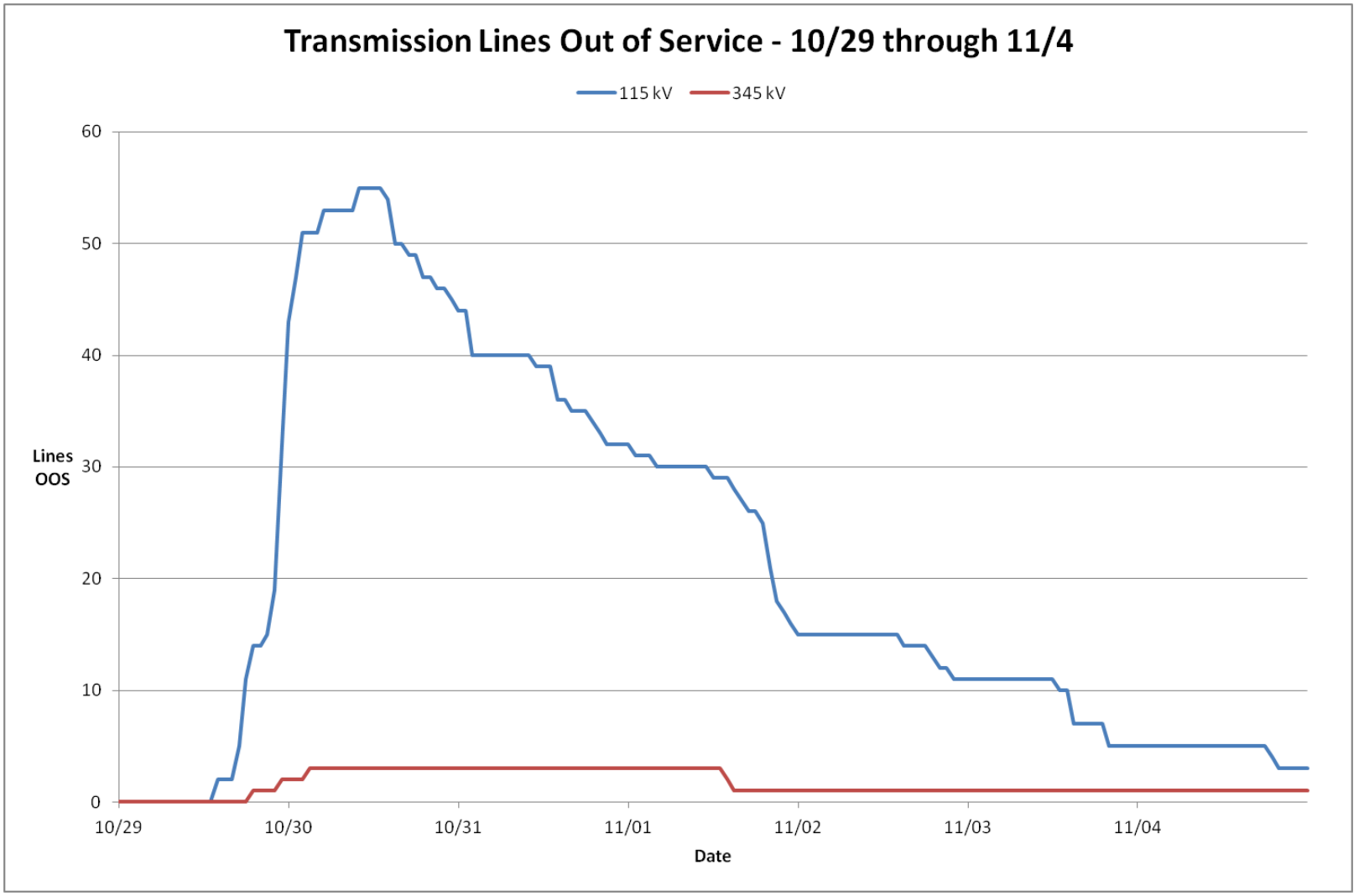
Transmission Outages by State During Storm 1200 on Saturday to 1200 on Sunday

State	Voltage Class	Number of Transmission Line Outages
Connecticut	345 kV	3
Connecticut	115 kV	29
Massachusetts	115 kV	19
Rhode Island	115 kV	1
New Hampshire	115 kV	3
Vermont, Maine	115 kV and 345 kV	0
Total		55

- The majority of transmission outages were caused by trees outside of the Utility Right of Way falling into the transmission lines

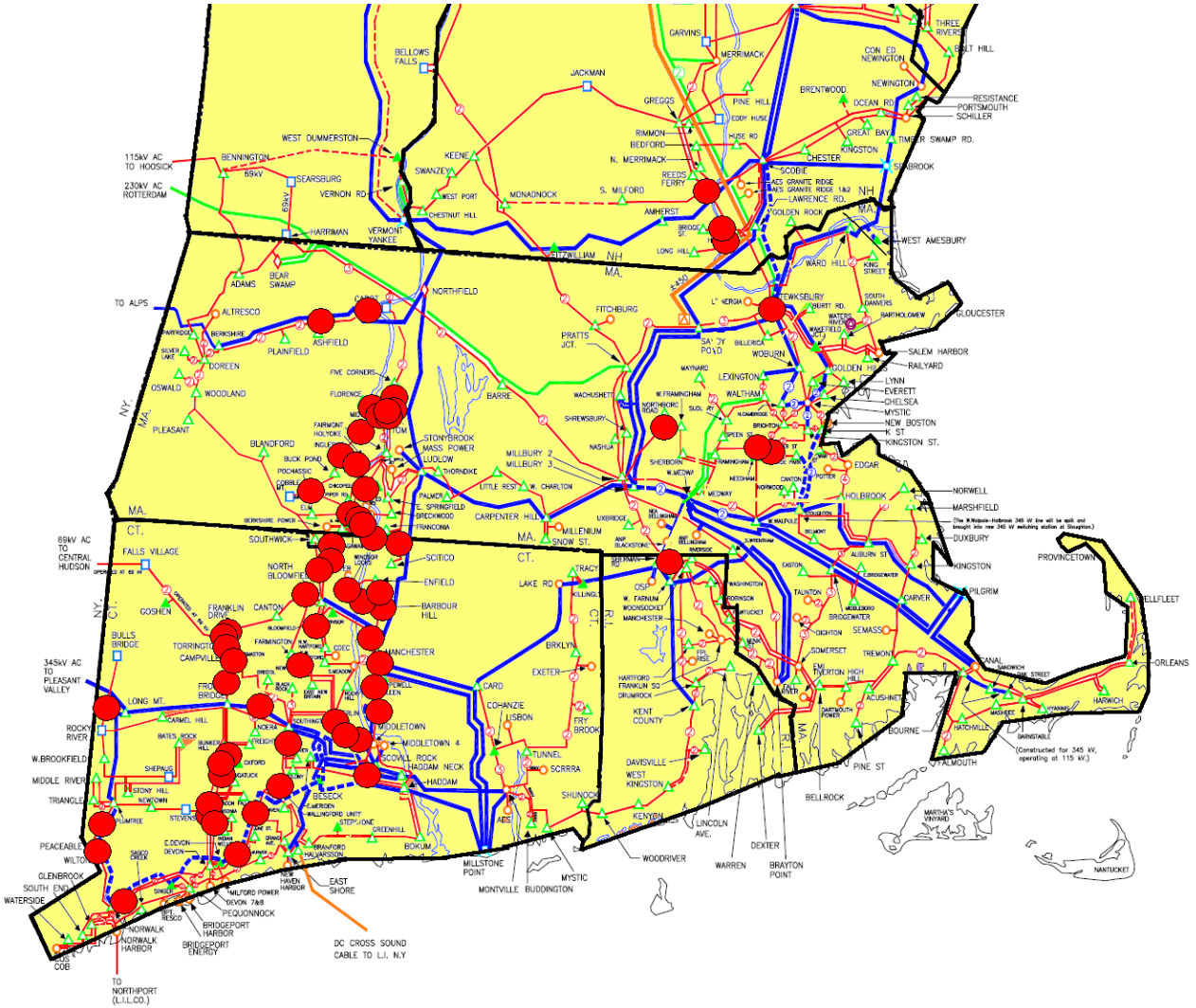
© 2011 ISO New England Inc.

Transmission Line Timeline



© 2011 ISO New England Inc.

Transmission Outages CT River Valley Hit Hard with Heavy Wet Snow in CT and MA



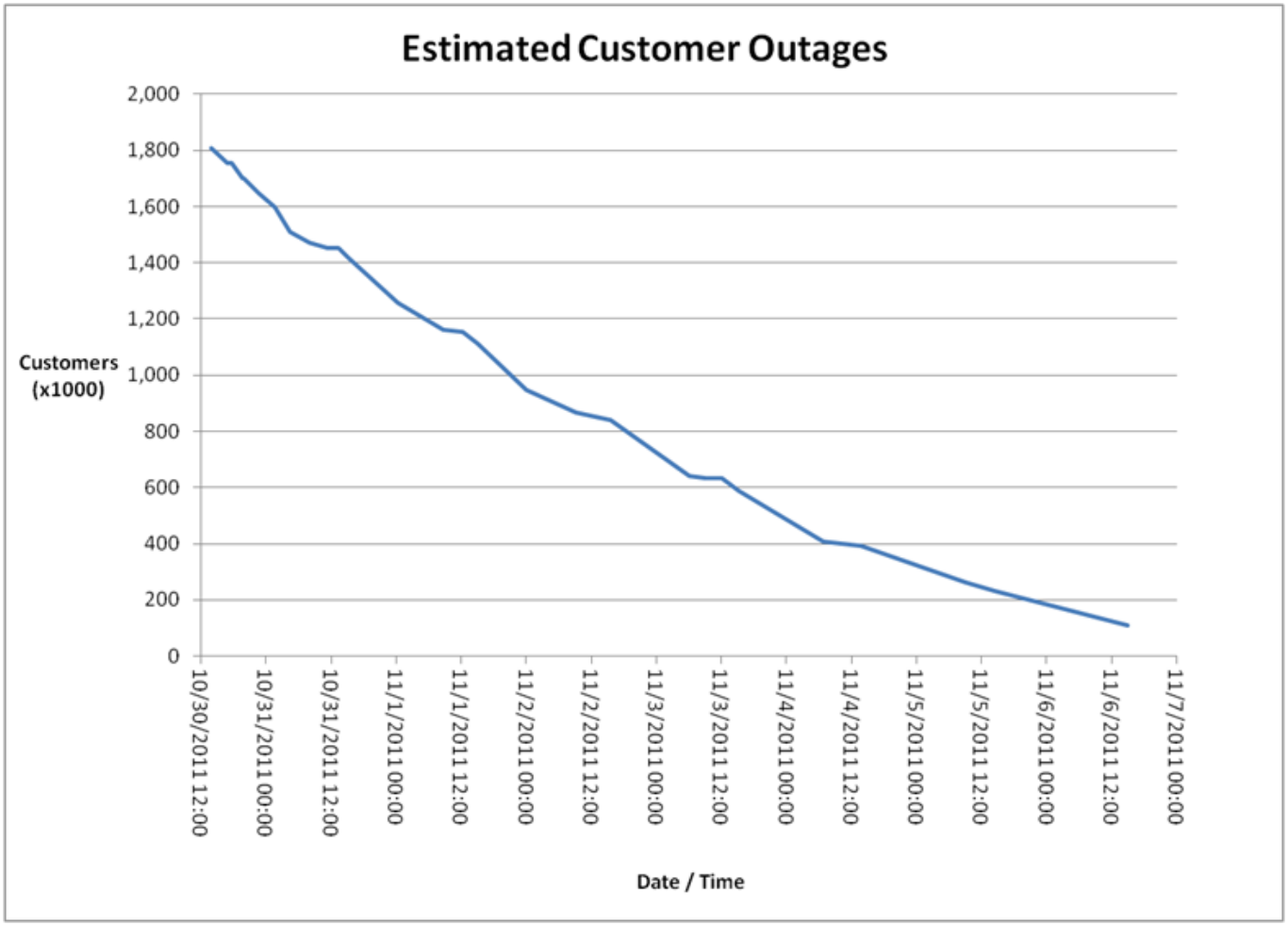
© 2011 ISO New England Inc.

Operating Limit Reliability Assessment

- No operating limits were exceeded before, during or after the storm period
  - For all real-time monitored New England Transmission Interface Limits (10/29/11 through 11/4/11)

© 2011 ISO New England Inc.

Estimated Customer Outages



Actual customer counts must be procured from distribution companies. These are estimates only.

© 2011 ISO New England Inc.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Announcement

NERC Hires New Enforcement Director

November 28, 2011

WASHINGTON, DC – The North American Electric Reliability Corporation (NERC) announced today that Kenneth Lotterhos will join NERC as associate general counsel and director of compliance enforcement, effective December 5.

Lotterhos comes to NERC from Navigant Consulting Inc., where he was managing director of the Energy Practice's Power Systems, Markets and Pricing group. Prior to joining Navigant, Lotterhos served at Edison Electric Institute as the director of Federal Regulatory Affairs.

Previously, Lotterhos clerked for the Energy Practice group at LeBouef, Lamb, Green and MacRae in Washington, DC, and held various engineering positions in the electric industry, including senior operations engineer for the Northeast Power Coordinating Council and a planning engineer for the Long Island Lighting Company.

"Ken's vast experience in the electric industry will benefit NERC, the industry and stakeholders," said Gerry Cauley, president and chief executive officer at NERC. "NERC has made much progress in the compliance enforcement program, the addition of Ken ensures we will continue that forward progress."

Lotterhos earned his Bachelor of Science degree in electric engineering from Polytechnic University of New York, and his juris doctorate from George Washington University Law School.









CONTACT:
Kimberly Mielcarek
202-383-2622

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

From: Kimberly Mielcarek
To: Kimberly Mielcarek
Subject: NERC Release - Reserve Margins Down in Some Areas, Report Finds
Date: Monday, November 28, 2011 5:47:58 PM

Media release

Reserve Margins Down in Some Areas; NERC Integrated Analysis Shows Impact of Environmental Regulations on Planning Decisions, Retrofits

Click here for announcement
Click here for *2011 Long-Term Reliability Assessment*

WASHINGTON, DC – A decrease in projected generation resources leads to declining planning reserve margins in some areas; however, a majority of areas appear to have adequate resource plans to meet projected peak demands over the next ten years, the North American Electric Reliability Corporation's (NERC) *2011 Long-Term Reliability Assessment* finds. The annual long-term reliability assessment provides an independent, ten-year view of the electric industry by evaluating key reliability indicators, including peak demand, energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other issues that may impact the reliability of the bulk power system.

For more information or assistance, please contact Kimberly Mielcarek.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1277077-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Media Release

Reserve Margins Down in Some Areas; NERC Integrated Analysis Shows Impact of Environmental Regulations on Planning Decisions, Retrofits

November 28, 2011

WASHINGTON, DC – A decrease in projected generation resources leads to declining planning reserve margins in some areas; however, a majority of areas appear to have adequate resource plans to meet projected peak demands over the next ten years, the North American Electric Reliability Corporation's (NERC) *2011 Long-Term Reliability Assessment* finds.

The annual long-term reliability assessment provides an independent, ten-year view of the electric industry by evaluating key reliability indicators, including peak demand, energy forecasts, resource adequacy, transmission development, changes in overall system characteristics and operating behavior, and other issues that may impact the reliability of the bulk power system.

"Though sufficient conceptual resource plans are in progress, for the ERCOT portion of Texas and for New England, more certainty is needed to address resource adequacy in the coming years," said Gerry Cauley, president and chief executive officer at NERC. "We will monitor these two areas in the upcoming year for progress in firming these resource projections."

Key issues and risks to bulk power system reliability identified in the long-term assessment include:

- **Reserve margins.** A decrease in projected generation resources has led to a decline in planning reserve margins in some Assessment Areas.
- **Gas-electric interdependency**. The growing dependence on natural gas as a primary fuel source of on-peak capacity must be considered in planning, and operational measures must be in place to minimize interdependency risks.









CONTACT:
Kimberly.Mielcarek@nerc.net

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

- **Variable generation.** Significant growth in wind and solar generation continues to be projected, surpassing on-peak growth forecasts of all other types of generation.
- **Demand-side management.** Increases in demand-side management continue to help offset future resource needs.
- **Transmission.** Growth is responding to increased demand for integrating and delivering new resources; construction is on pace with projections.
- **Environmental regulations.** While more flexibility is provided in some proposed rules, the cumulative effect from environmental regulations may reduce reserve margins in ways that could affect bulk power system reliability, depending on the scope and timing of final regulation implementation.

The report also provides a section that updates NERC's *2010 Special Reliability Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*. In the United States, the Environmental Protection Agency is in the process of promulgating four regulations: the proposed Coal Combustion Residuals rule, the proposed Mercury and Air Toxics Standards for Utilities, the proposed Cooling Water Intake Structures rule -316(b), and the final Cross-State Air Pollution rule.

While not all of these four regulations are final, and their affects cannot be completely measured, material changes have occurred to these regulations since NERC's 2010 assessment. While many factors affect an owner's decision to retire or retrofit a facility, NERC's analysis of the integrated impact of these regulations on planning decisions shows 36 GW in the 2018 moderate case of projected accelerated retirements and derates. Though this amount appears lower than the 2010 assessment projected, 25 GW of retirements have been announced since then and are no longer included in the projected retirement numbers. More importantly, industry information continues to show that significant retrofits will be needed over the next four years in order to comply with proposed utility air toxics regulations.

"With MACT as the primary driver, the industry faces considerable operational challenges to complete, coordinate and schedule the necessary environmental retrofits," Cauley said. "To ensure bulk power system reliability, sufficient time and certainty to schedule retrofits of more than 500 units, as well as acquire replacement resources or prepare system reinforcements is needed."

The assessment shows five key conclusions:

- **Timing.** Compliance deadlines will challenge the electric industry's planning horizons, processes and schedules. Implementation of the proposed rules, while successfully preserving bulk power system reliability, may be highly dependent on the amount of time given to the industry to comply with future regulations, and the tools in place to support the industry's transition.
- **Regionality.** The fuel-mix differs greatly across the country, and each area will face different dynamics. States decisions on rule implementation could greatly influence cumulative impacts.
- **Outage coordination.** Given the tight window for compliance, many affected units may need to take maintenance outages concurrently, which can exacerbate resource adequacy concerns and reduce needed flexibility.

- **Transmission and operational issues.** The retirement of larger and/or strategically situated generating units will cause changes to the power flows and stability dynamics of the bulk power system. These changing characteristics will require enhancements to the interconnected transmission system to provide reactive and voltages support, address thermal constraints and provide system stability.
- **Uncertainty.** A major concern is the lack of certainty on both the generating supply side and from the Environmental Protection Agency due to rules not being finalized.

Recommendations from the assessment to address these key issues include:

- **Regulators.** Consider time and scope of regulation and affects on bulk power system reliability. Coordination is needed among federal agencies to ensure the industry is not forced to violate one regulation in order to meet another.
- **Industry.** Employ available tools to mitigate potential reliability concerns through any resource transition.
- **NERC.** Continue to assess implications of regulations as greater certainty emerges around industry obligations, technologies, timelines and targets.

Click here to download the *2011 Long-Term Reliability Assessment*.

###

The North American Electric Reliability Corporation's mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission in the United States to establish and enforce reliability standards for the bulk-power system. NERC has equivalent relationships with provincial and federal authorities in Canada. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel. Learn more at www.nerc.com

Proposed Revision 2

SERC Regional Standards Development Procedure

Exhibit C
to the
Amended and Restated
Regional Entity Delegation Agreement
between

North American Electric Reliability Corporation
and
SERC Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SERC
SERC Reliability Corporation

Exhibit C – Regional Standard Development Procedure

Exhibit C sets forth SERC Reliability Corporation's standards development procedure, which NERC agrees meets the following common attributes:

COMMON ATTRIBUTE 1

Proposed regional reliability standards shall be subject to approval by NERC, as the electric reliability organization, and by FERC before becoming mandatory and enforceable under Section 215 of the FPA [add reference to any applicable authorities in Canada and Mexico]. No regional reliability standard shall be effective within the [Regional Entity Name] area unless filed by NERC with FERC [and applicable authorities in Canada and Mexico] and approved by FERC [and applicable authorities in Canada and Mexico].

COMMON ATTRIBUTE 2

[Regional Entity Name] regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. A [Regional Entity Name] reliability standard shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. A regional reliability standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.

COMMON ATTRIBUTE 3

[Regional Entity Name] regional reliability standards, when approved by FERC [add applicable authorities in Canada], shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the [Regional Entity Name] area, regardless of membership in the region.

COMMON ATTRIBUTE 4

Requester — The requester is the sponsor of the regional reliability standard request may assist in the development of the standard. Any member of [Regional Entity Name], or group within [Regional Entity Name] shall be allowed to request that a regional reliability standard be developed, modified, or withdrawn. Additionally, any entity (person, organization, company, government agency, individual, etc.) that is directly and materially affected by the reliability of the bulk

power system in the [Regional Entity Name] area shall be allowed to request a regional reliability standard be developed, modified, or withdrawn.

COMMON ATTRIBUTE 5

[Standards or other named] committee — The [Regional Entity Name] [standards] committee manages the standards development process. The [standards] committee will consider which requests for new or revised standards shall be assigned for development (or existing standards considered for deletion). The [standards] committee will advise the [Regional Entity Name] board on standards presented for adoption.

COMMON ATTRIBUTE 6A [REGISTERED BALLOT BODY APPROACH]

The registered ballot body comprises all entities or individuals that qualify for one of the stakeholder segments; are registered with [Regional Entity Name] as potential ballot participants in the voting on standards; and are current with any designated fees. Each member of the registered ballot body is eligible to vote on standards. [Each standard action has its own ballot pool formed of interested members of the registered ballot body. Each ballot pool comprises those members of the registered ballot body that respond to a pre-ballot survey for that particular standard action indicating their desire to participate in such a ballot pool.] The representation model of the registered ballot body is provided in Appendix A.]

COMMON ATTRIBUTE 7

[Regional Entity Name] will coordinate with NERC such that the acknowledgement of receipt of a standard request identified in step 1 [SERC Step 4], notice of comment posting period identified in step 4 [SERC Step 7], and notice for vote identified in step 5 [SERC Step 9] below are concurrently posted on both the [Regional Entity Name] and NERC websites.

COMMON ATTRIBUTE 8

An acceptable standard request shall contain a description of the proposed regional reliability standard subject matter containing sufficiently descriptive detail to clearly define the purpose, scope, impacted parties, and other relevant information of the proposed standard.

COMMON ATTRIBUTE 9

Within [no greater than 60] days of receipt of a completed standard request, the [standards] committee shall determine the disposition of the standard request.

COMMON ATTRIBUTE 10

The [standards] committee may take one of the following actions:

- Accept the standard request as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The [standards] committee may, at its discretion, expand or narrow the scope of the standard request under consideration. The [standards] committee shall prioritize the development of standard in relation to other proposed standards, as may be required based on the volume of requests and resources.
- Reject the standard request. If the [standards] committee rejects a standard request, a written explanation for rejection will be delivered to the requester within [no greater than 30] days of the decision.
- Remand the standard request back to the requester for additional work. The standards process manager will make reasonable efforts to assist the requester in addressing the deficiencies identified by the [standards] committee. The requester may then resubmit the modified standard request using the process above. The requester may choose to withdraw the standard request from further consideration prior to acceptance by the [standards] committee.

COMMON ATTRIBUTE 11

Any standard request that is accepted by the [standards] committee for development of a standard (or modification or deletion of an existing standard) shall be posted for public viewing on the [Regional Entity Name] website within [no greater than 30] days of acceptance by the committee.

COMMON ATTRIBUTE 12

The standards process manager shall submit the proposed members of the drafting team to the [standards] committee. The [standards] committee shall approve the drafting team membership within 60 days of accepting a standard request for development, modifying the recommendations of the standards process manager as the committee deems appropriate, and assign development of the proposed standard to the drafting team.

COMMON ATTRIBUTE 13

At the direction from the [standards] committee, the standards process manager shall facilitate the posting of the draft standard on the [Regional Entity Name] website, along with a draft implementation plan and supporting documents, for a no less than a [30]-day] comment period. The standards process manager shall provide notice to [Regional Entity Name] stakeholders and other potentially interested entities, both within and outside of the [Regional Entity Name] area, of

the posting using communication procedures then currently in effect or by other means as deemed appropriate.

COMMON ATTRIBUTE 14

The drafting team shall prepare a summary of the comments received and the changes made to the proposed standard as a result of these comments. The drafting team shall summarize comments that were rejected by the drafting team and the reason(s) that these comments were rejected, in part or whole. The summary, along with a response to each comment received will be posted on the [Regional Entity Name] website no later than the next posting of the proposed standard.

COMMON ATTRIBUTE 15

Upon recommendation of the drafting team, and if the [standards] committee concurs that all of the requirements for development of the standard have been met, the standards process manager shall post the proposed standard and implementation plan for ballot and shall announce the vote to approve the standard, including when the vote will be conducted and the method for voting. Once the notice for a vote has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

COMMON ATTRIBUTE 16

The standards process manager shall schedule a vote by the [Regional Entity Name] [registered ballot body/[standards] committee]. The vote shall commence no sooner than [15] days and no later than [30] days following the issuance of the notice for the vote.

COMMON ATTRIBUTE 17

The [standards] committee shall give due consideration to the work of the drafting team, as well as the comments of stakeholders and minority objections, in approving a proposed regional reliability standard for submittal to the [Regional Entity Name] board. The [standards] committee may vote to approve or not approve the standard. Alternatively, the [standards] committee may remand the standard to the drafting team for further work or form a new drafting team for that purpose.

COMMON ATTRIBUTE 18

The [standards] committee may not itself modify the standard without issuing a new notice to stakeholders regarding a vote of the modified standard.

COMMON ATTRIBUTE 19

Actions by the committee shall be recorded in the regular minutes of the committee.

COMMON ATTRIBUTE 20

Under no circumstances may the board substantively modify the proposed regional reliability standard.

COMMON ATTRIBUTE 21

Once a regional reliability standard is approved by the board, the standard will be submitted to NERC for approval and filing with FERC [and applicable authorities in Canada and Mexico.]

COMMON ATTRIBUTE 22

Open - Participation in the development of a regional reliability standard shall be open to all organizations that are directly and materially affected by the [Regional Entity Name] bulk power system reliability. There shall be no undue financial barriers to participation. Participation shall not be conditioned upon membership in [Regional Entity Name], and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements. Meetings of drafting teams shall be open to the [Regional Entity Name] members and others.

COMMON ATTRIBUTE 23

Balanced - The [Regional Entity Name] standards development process strives to have an appropriate balance of interests and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter.

COMMON ATTRIBUTE 24

Inclusive — Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the bulk power system in the [Regional Entity Name] area shall have a right to participate by: a) expressing a position and its basis, b) having that position considered, and c) having the right to appeal.

COMMON ATTRIBUTE 25

Fair due process — The regional reliability standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the procedure shall include public notice of the intent to develop a

standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.

COMMON ATTRIBUTE 26

Transparent — All actions material to the development of regional reliability standards shall be transparent. All standards development meetings shall be open and publicly noticed on the regional entity's Web site.

COMMON ATTRIBUTE 27

Does not unnecessarily delay development of the proposed reliability standard.

COMMON ATTRIBUTE 28

Each standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk power system. Each standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

COMMON ATTRIBUTE 29

While reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. Reliability is a necessity for electricity markets, and robust electricity markets can support reliability. Recognizing that bulk power system reliability and electricity markets are inseparable and mutually interdependent, all regional reliability standards shall be consistent with NERC's market interface principles. Consideration of the market interface principles is intended to ensure that standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

COMMON ATTRIBUTE 30

To ensure uniformity of regional reliability standards, a regional reliability standard shall consist of the elements identified in this section of the procedure. These elements are intended to apply a systematic discipline in the development and revision of standards. This discipline is necessary to achieving standards that are measurable, enforceable, and consistent.

COMMON ATTRIBUTE 31

All mandatory requirements of a regional reliability standard shall be within the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself.

COMMON ATTRIBUTE 32

Clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions.

If not applicable to the entire [Regional Entity Name] area, then a clear identification of the portion of the bulk power system to which the standard applies. Any limitation on the applicability of the standard based on electric facility requirements should be described.

COMMON ATTRIBUTE 33

Each requirement shall be addressed by one or more measures. Measures are used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measure will identify to whom the measure applies and the expected level of performance or outcomes required demonstrating compliance. Each measure shall be tangible, practical, and as objective as is practical. It is important to realize that measures are proxies to assess required performance or outcomes. Achieving the measure should be a necessary and sufficient indicator that the requirement was met. Each measure shall clearly refer to the requirement(s) to which it applies.

COMMON ATTRIBUTE 34

Defines for each measure:

- The specific data or information that is required to measure performance or outcomes.
- The entity that is responsible for providing the data or information for measuring performance or outcomes.
- The process that will be used to evaluate data or information for the purpose of assessing performance or outcomes.
- The entity that is responsible for evaluating data or information to assess performance or outcomes.
- The time period in which performance or outcomes is measured, evaluated, and then reset.
- Measurement data retention requirements and assignment of responsibility for data archiving.
- Violation severity levels.

Revision History

Revision	Date	Comments
0	October 25, 2006	Document Origination
1	October 10, 2007	Document revised to change to a registered ballot body approach to approve standards, changed "Manager of Reliability Services" to Manager of Reliability Standards," changed the RSS meeting notice period to 21 days, changed the review period for this procedure from five to three years, and moved from the Standing Committee Executive Committees to the SERC Standards Committee the ability to remand a SAR back to the Requester for additional work.
2	Ballot Pool approved: September 29, 2011	Update to 1) address document Three-Year Review and Re-Approval Requirements; 2) address issues identified during the SERC 2009 audit by NERC; 3) make revisions to improve process efficiency and reduce the time required to develop a regional standard; 4) ensure alignment with the NERC Standard Processes Manual, Revision 1 dated November 2010; and 5) changed the review period for this procedure back from three to five years..

Responsible SERC Group(s)

SERC Standards Committee (SC)

Review and Re-Approval Requirements

This document will be reviewed every five years or as appropriate by the SERC Standards Committee for possible revision

List of Appendices

Appendix A: Stakeholder Representation
Appendix B: Principles, Characteristics, and Special Procedures
Appendix C: SERC Regional Reliability Standard Authorization Request Form
Appendix D: Elements of a SERC Regional Reliability Standard
Appendix E: Comment Form for Draft SERC Regional Reliability Standard
Appendix F: SERC Consideration of Comments Form
Appendix G: SERC Process Flow Diagram

Introduction

This procedure defines the process for development, revision, reaffirmation, and withdrawal of a regional reliability standard by the SERC Reliability Corporation (SERC). SERC is a regional entity authorized through an approved delegation agreement with the North American Electric Reliability Corporation (NERC) to propose regional reliability standards in accordance with Section 215 of the Federal Power Act (FPA), the U.S. Federal Energy Regulatory Commission (FERC) Order No. 672, and Section 39 of Title 18 of the U.S. Code of Federal Regulations (18 C.F.R. § 39).

SERC Regional Reliability Standards apply to the planning, operation, and critical infrastructure protection of the Bulk Electric System in the SERC Region. Proposed SERC Regional Reliability Standards shall be subject to approval by NERC, as the electric reliability organization, and by FERC before becoming mandatory and enforceable under Section 215 of the FPA. No SERC Regional Reliability Standard shall be effective within the SERC Region unless filed by NERC with FERC and approved by FERC.

SERC Regional Reliability Standards shall provide for as much uniformity as possible with reliability standards across the interconnected Bulk Electric System of the North American continent. A SERC Regional Reliability Standard shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or regional difference necessitated by a physical difference in the Bulk Electric System. A SERC Regional Reliability Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.

SERC Regional Reliability Standards, when approved by FERC, shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable Bulk Electric System owners, operators, and users within the SERC Region, regardless of membership in the region.

Process Roles

Requester: The requester is the sponsor of the SERC Regional Reliability Standard request and may assist in the development of the standard. Any Member Company of SERC, or any group (or member of a group) within SERC (i.e., committee, subcommittee, working group, study group, task force, or SERC staff), shall be allowed to request that a SERC Regional Reliability Standard be developed, modified, or withdrawn. Additionally, any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System shall be allowed to request that a SERC Regional Reliability Standard be developed, modified, or withdrawn.

SERC Board of Directors: The SERC Board of Directors shall consider for approval as SERC Regional Reliability Standards, those Standards that have been developed and approved by this procedure. Once the Board approves a SERC Regional Reliability Standard, such Standard shall be submitted to NERC for approval. When approved by NERC, it shall be submitted to FERC for approval.

SERC Staff: The SERC Manager of Reliability Standards is responsible for forwarding a request for the development, modification or withdrawal of SERC Regional Reliability Standards to the SERC Standards Committee. The SERC Staff shall facilitate all steps in this process.

SERC Standards Committee: The SERC Regional Reliability Standard Development Procedure shall be administered by the SERC Standards Committee (SC). The SERC SC is responsible for ensuring that the development, modification or withdrawal of SERC Regional Reliability Standards is in accordance with the steps in this procedure. The SERC SC will ensure the integrity of the process and the consistency of quality and completeness of the SERC Regional Reliability Standards.

SERC Standing Committees: The SERC Standing Committees will perform a high level technical review of the SAR to determine which requests for new or revised standards shall be assigned for development (or existing standards considered for deletion). The Standing Committees will appoint the standard drafting team (Responsible SERC Subgroup).

The current SERC Standing Committees are the Engineering Committee (EC), Operating Committee (OC), and Critical Infrastructure Protection Committee (CIPC). The Standing Committees are balanced stakeholder committees, inclusive of all stakeholder interests that provide for or are materially impacted by the reliability of the Bulk Electric System.

Responsible SERC Subgroup (RSS): Responsible SERC Subgroups are teams, responsible for drafting the standard; they are also referred to as the Standard Drafting Team (SDT). The RSS may include technical experts and be based around a

permanent SERC Standing Committee subgroup. An RSS is established expressly to draft the standard. Membership on an RSS will be assigned by the SERC EC, OC, and/or CIPC. The requester may act as the RSS, serve on the RSS, or otherwise assist the RSS. SERC membership is not a prerequisite for serving on an RSS. The RSS will:

- Develop the details of the SERC Regional Reliability Standard,
- Consider and respond to industry comments,
- Participate in forums to help build consensus on draft SERC Regional Reliability Standards,
- Assist in the implementation of approved SERC Regional Reliability Standards,
- Provide technical oversight in response to changing industry conditions, and
- Assist in the identification of the need for new SERC Regional Reliability Standards.

Registered Ballot Body (RBB): The registered ballot body votes to approve standards. The RBB comprises all entities or individuals that qualify for one of the SERC industry Sectors, and are registered with SERC as potential ballot participants in the voting on standards. SERC membership is not a prerequisite for registering with SERC as a potential ballot participant. Any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System shall be allowed to register as a potential ballot participant.

Each member of the registered ballot body is eligible to vote on standards. Each standard action has its own ballot pool formed of interested members of the registered ballot body.

Ballot Pool: Each standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot survey for that particular standard action. The ballot pool will ensure, through its vote, the need for and technical merits of a proposed standard action and the appropriate consideration of views and objections received during the development process. The ballot pool votes to approve each standards action.

Process Steps

Note: The term “days” below refers to calendar days.

SERC will coordinate with NERC such that the acknowledgement of receipt of an accepted standard request identified in Step 4, notice of comment posting period identified in Step 7, and notice for vote identified in Step 9 below are concurrently posted on both the SERC and NERC websites.

Step 1: Request for a new SERC Regional Reliability Standard or modification to, or withdrawal of an existing SERC Regional Reliability Standard

A request to develop, modify or withdraw a SERC Regional Reliability Standard shall be submitted, using the SERC Regional Reliability Standard Authorization Request (SAR) Form (see Appendix C), to the SERC Manager of Reliability Standards (via e-mail to regstd@serc1.org) by any Member Company of SERC, or any group (or member of a group) within SERC (i.e., committee, subcommittee, working group, study group, task force, or SERC staff), or any entity that is directly and materially affected by reliability of the SERC Bulk Electric System. The SERC SAR Form can be downloaded from the SERC website (www.serc1.org).

An acceptable SAR shall contain a description of the proposed regional reliability standard subject matter with sufficient descriptive detail of the proposed standard to clearly define the purpose, scope, impacted parties, and other relevant information. The requester must verify in the Justification section of the SAR that the request meets one of the following criteria:

- The proposed standard covers a topic addressed in a continent-wide standard, but the proposed standard will include requirements more stringent than those in the continent-wide standard.
- The proposed standard addresses matters that the continent-wide reliability standards do not.
- The proposed standard is necessitated by a physical difference in the Bulk Electric System.

SERC Staff shall verify that the SAR Form has been adequately completed. Within 15 days of receiving the SAR, the SERC Manager of Reliability Standards or his designee will electronically acknowledge receipt of the SAR, and will forward the SAR to the SERC Standards Committee. The SERC Manager of Reliability Standards may offer the Requester suggestions regarding changes or improvements to enhance the clarity of the proposed standards work and to assist the SERC Standards Committee in understanding the requester’s intent and objectives. The requester is free to accept or reject these suggestions.

Step 2: Assignment of SERC Regional Reliability Standard Request

The SERC Standards Committee will review the SAR to ensure it is not in conflict with or duplication of a current standard or a standards drafting effort already proposed or in progress. Within 15 days after receiving the SAR from the SERC Manager of Reliability Standards, the SERC Standards Committee will take one of the two following actions:

- Assign the SAR to the appropriate SERC Standing Committee(s). SERC Staff will forward the SAR to the Chair(s) and Executive Committee(s) of the appropriate SERC Standing Committee(s).

- Remand the SAR back to the Requester for additional work. The SERC Manager of Reliability Standards will make reasonable efforts to assist the Requester in addressing the deficiencies identified by the SERC Standards Committee. The Requester may then resubmit the modified SAR using the process above. The requester may choose to withdraw the SAR from further consideration.

Step 3: Acceptance of a SERC Regional Reliability Standard Request

Within 60 days of receipt of a completed SAR, the Executive Committee(s) of the assigned SERC Standing Committee(s) shall determine the disposition of the SAR. The committee(s) shall verify that the SAR requester has provided information to justify that the request meets one of the following criteria:

- The proposed standard covers a topic addressed in a continent-wide standard, but the proposed standard will include requirements more stringent than those in the continent-wide standard.
- The proposed standard addresses matters that the continent-wide reliability standards do not.
- The proposed standard is necessitated by a physical difference in the Bulk Electric System.

The committee may take one of the two following actions:

- Accept the SAR as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The committee(s) may, at its discretion, expand or narrow the scope of the SAR under consideration. The committee(s) shall prioritize the development of standard in relation to other proposed standards, as may be required based on the volume of requests and resources.

- Reject the SAR. If the committee(s) rejects a SAR, a written explanation for rejection will be delivered to the Requester within 30 days of the decision.

Deliberations and decisions of the Executive Committee(s) of the assigned SERC Standing Committee(s) concerning requests shall be made and documented in accordance with the SERC Standing Committee rules and procedures then in effect.

Step 4: Posting of SERC Regional Reliability Standard Request

Any SAR that is accepted by the Executive Committee(s) of the assigned SERC Standing Committee(s) for development of a standard (or modification or deletion of an existing standard) shall be posted for public viewing on the SERC website within 30 days of acceptance by the committee. A comments form and a nomination form to serve on the drafting team (Responsible SERC Subgroup) will be included in the posting. A notice of the posting for a 30-day comment period will be sent to all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to NERC, the regional standards area of the other Regional Entities, individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives to seek input on the proposed SAR. SERC Staff will perform this posting on the SERC website and coordinate or send correspondences described in this and other steps of the process. SERC Staff will assist in developing a response to any comments received. Any accompanying revision to the SAR based on comments received must be approved by the Executive Committee(s) of the assigned SERC Standing Committee(s).

Step 5: Formation of a Responsible SERC Subgroup

Within 60 days of accepting a SAR for development, the Executive Committee(s) of the assigned SERC Standing Committee(s) shall assign and direct the proposal to the appropriate Responsible SERC Subgroup (RSS) to develop the draft Regional Reliability Standard. The RSS may be a permanent Standing Committee subgroup (augmented by other persons as may be appropriate to address the subject matter of the proposed standard), or a task force established expressly by the Executive Committee(s) for drafting the standard. SERC membership is not a prerequisite for serving on an RSS.

After consulting with the Executive Committee(s) of the assigned SERC Standing Committee(s) as necessary, the SERC Standards Committee (SC) will assign a preliminary date on which the RSS is expected to have ready a completed draft Standard and associated supporting documentation available for consideration.

Step 6: Drafting of a SERC Regional Reliability Standard

The RSS shall develop a work plan for completing the regional reliability standard, including the establishment of a milestone schedule for completing critical elements of the work in sufficient detail to ensure that the RSS will meet the objectives established by the SC. The RSS shall submit its work plan to the SC for its concurrence. Any subsequent revision to the plan by the RSS which delays balloting the draft standard by 60 days or longer will be presented to the SC for its concurrence.

The RSS shall convene periodically, either in person or by electronic means as necessary, establish work teams (made up of members of the RSS) as necessary, and perform other activities to complete the proposed standard within the milestone date(s) agreed upon by the SC. All in-person RSS meetings or portions of meetings associated with development of the draft standard shall be open and publicly noticed on the SERC website for a minimum of twenty-one (21) calendar days prior to the meeting. All conference call and electronic (WebEx) RSS meetings or portions of meetings associated with development of the draft standard shall be open and publicly noticed on the SERC website for a minimum of seven (7) calendar days prior to the meeting. All RSS meeting attendees are required to register via the SERC website.

The RSS shall consider all comments received on the posting of the SAR and shall develop a draft SERC Regional Reliability Standard that will address the accepted SAR. The RSS shall use the most current version of the approved NERC Reliability Standard template and its associated elements posted on the NERC website as the format for the draft standard

The work product of the RSS will be completed before taking the draft standard to ballot (Steps 9 and 10) and each item of the work product will be included as background information for at least one comments posting period (Step 7). The work product will consist of the following:

- A draft Standard consistent with the SAR on which it was based.
- An assessment of the reliability impact of the standard request within the region and in neighboring regions, including appropriate input from the neighboring regions if the standard request is likely to impact any neighboring region. Communications between neighboring regions may be through the regional standard drafting teams, the regional standards development staff, or other means as appropriate.
- An implementation plan, including the nature, extent and duration of field-testing, if any.
- Identification of any existing Standard that will be deleted, in part or whole, or otherwise impacted by the implementation of the draft Standard
- Technical reports, white papers and/or work papers that provide technical support for the draft Standard under consideration.
- Documentation of the perceived reliability impact should the Standard be approved.

The RSS shall regularly inform the SC, at a frequency determined by the SC (RSS shall deliver a status report at every SC meeting at a minimum), of its progress in meeting a timely completion of the draft standard. The RSS may, with justification, request of the SC scope changes from the SAR at any point in the standard development process.

The RSS shall submit the draft SERC Regional Reliability Standard and supporting documentation to the SC for review***.*** The RSS will send any revised SERC Regional Reliability Standard to the SC in both “Clean” and “Tracking” formats. The RSS shall also send the SC an accompanying Comments Form which may include specific questions addressing the major issues associated with the new or revised standard. In

any event, the Comments Form must also allow for general comments on the standard (see Appendix E for sample form). The SC will verify that the proposed standard is consistent with the SAR on which it was based. The SERC Regional Reliability Draft Standards Comments Form can be downloaded from the SERC website (www.serc1.org).

Step 7: Posting of a Draft SERC Regional Reliability Standard

The SERC Standards Committee shall send to the SERC Manager of Reliability Standards the draft SERC Regional Reliability Standard, along with a draft implementation plan and supporting documents, for comments. SERC Staff will post these documents on the SERC website for thirty (30) calendar days. A notice of the posting for comment will be sent to all SERC Standing Committees representatives and alternates. In addition, the request will be sent (via e-mail) to NERC, the regional standards area of the other Regional Entities, individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives to seek input on the draft SERC Regional Reliability Standard. Comments shall be submitted electronically (via e-mail) to regstd@serc1.org. All comments are due by the close of business on the 30th calendar day of posting. If the comment due date falls on a weekend or nationally recognized holiday, the comments shall be due by the close of business on the next regularly scheduled business day.

Step 8: Standard Drafting Team Review of Comments

SERC Staff shall forward all comments received to the RSS. The RSS shall review the comments received and revise the draft SERC Regional Reliability Standard as needed. The RSS shall develop a written response to each comment received using the Consideration of Comments Form Template (see Appendix F). The SERC Consideration of Comments Form Template can be downloaded from the SERC website (www.serc1.org). The completed Consideration of Comments Form will be posted on the SERC website.

The RSS shall summarize comments that were rejected by the RSS and the reason(s) that these comments were rejected, in part or whole. The RSS shall submit to the SC the summary of comments rejected, the completed Consideration of Comments form, and any resulting revisions to the draft SERC Regional Reliability Standard.

If needed, a second draft of the SERC Regional Reliability Standard (along with the summary of comments rejected and the Consideration of Comments from the previous posting) will be posted for another comment period. Such comment period shall be for thirty (30) calendar days. A notice of the posting for comment will be sent to all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to NERC, the regional standards area of the other Regional Entities, individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives to seek input on the revised draft SERC Regional Reliability Standard.

Based on comments received to the posting, Step 7 will be repeated as necessary until the RSS and the SC agree that no additional comments posting periods are warranted.

The SERC Manager of Reliability Standards will then request the NERC regional standards staff to make arrangements for a formal quality review of the draft standard. The RSS will develop responses to any recommendations from that review, including developing revisions to the draft standard if appropriate. The SDT and SC must agree on those responses prior to taking one of the two following actions:

- Submit the draft standard for an additional comment posting period (Step 7); or
- Submit the draft standard to the SERC Ballot Body for approval (Step 9).

The SC will determine if an additional NERC formal quality review will be requested for a draft standard which has been revised based on responses to an addition comments posting period.

Step 9: Notice of Vote to Approve a SERC Regional Reliability Standard

The Responsible SERC Subgroup shall submit the summary of comments rejected and the Consideration of Comments document along with the final draft of the proposed SERC Regional Reliability Standard (both "Tracking" and "Clean" versions for standard revisions) to the SERC Manager of Reliability Standards for posting on the SERC website at least 15 days prior to requesting approval of the standard.

The SERC Manager of Reliability Standards shall post the proposed standard and implementation plan for ballot and shall announce the vote to approve the standard, including when the vote will be conducted and the method for voting. Once the notice for a vote has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

Ballot Pool: The SERC Manager of Reliability Standards shall establish a ballot pool for a standard action at least 15 days prior to the start of a ballot. The SERC Manager of Reliability Standards shall send a notice to every entity in the Registered Ballot Body. The purpose of this notice is to establish a ballot pool to participate in the ballot of the proposed standards action.

Any member of the Registered Ballot Body may join or drop out of a ballot pool until the ballot period begins (Step 10). No Registered Ballot Body member may join or leave the ballot pool once the first ballot starts. The SERC Manager of Reliability Standards shall coordinate changes to the membership of the ballot pool and publicly post the standard ballot pool for each standard action.

The SERC Manager of Reliability Standards shall schedule a vote by the ballot pool for approval. The vote shall commence no sooner than 15 days and no later than 30 days following the issuance of the notice for the vote.

Step 10: SERC Ballot Pool of Registered Ballot Body Approval

The Ballot Pool shall have a minimum of ten (10) days to vote on a standards action. The Ballot Pool should give due consideration to the work of the RSS, as well as the comments of stakeholders and minority objections, in approving a proposed regional reliability standard. The Ballot Pool may vote to approve or not approve the standard. The ballot will include provisions for comments. The RSS shall develop a written response to each ballot comment received.

If approval by the RBB is not obtained, the Standing Committee(s) will determine if the draft SERC Regional Reliability Standard is to be sent back to the RSS to repeat Step 8 to incorporate any RBB or SERC Standing Committee(s) comments, form a new RSS for that purpose, or to withdraw the proposed SERC Regional Reliability Standard.

If the standard is withdrawn, the reason for such will be posted on the SERC website. A notice of the posting will be sent to all SERC Standing Committee representatives and alternates. In addition, the notice will be sent (via e-mail) to NERC, the regional standards area of the other Regional Entities, individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives.

Step 11: Submission of SERC Regional Reliability Standards to NERC to post for comments

Once the SERC Regional Reliability Standard is approved by the SERC RBB, the SERC Manager of Reliability Standards will forward it to NERC and request that they post it for comments in accordance with the NERC Regional Reliability Standards Evaluation Procedure.

The Responsible SERC Subgroup will develop a response to any comments received and submit it along with any associated standard modifications to the SERC Standards Committee for approval. The SERC Standards Committee may approve minor editorial type modifications that do not have a substantive impact. If the Responsible SERC Subgroup proposes any substantive modifications, the SERC Standards Committee may 1) remand it back to the Responsible SERC Subgroup for further consideration; or 2) accept the proposed modification and send it back to Step 9 to re-ballot the standard.

Step 12: Approval of SERC Regional Reliability Standards by the SERC Board of Directors

The SERC Board of Directors shall consider approval of any SERC Regional Reliability Standard that has been approved by the SERC RBB and has received SERC Standards Committee approval of the resolution of comments received during the Step 11 posting. A SERC Regional Reliability Standard submitted for approval by the SERC Board of Directors must be posted for notification on the SERC website at least 15 days

prior to action by the SERC Board of Directors. A notice of the posting will be sent to all SERC Board of Directors representatives and alternates, and to all SERC Standing Committee representatives and alternates. In addition, the notice will be sent (via e-mail) to NERC, the regional standards area of the other Regional Entities and to any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System.

The SERC Board of Directors shall consider the comments received, the responses provided, and any dissenting opinions. The SERC Board of Directors shall approve or reject a SERC Regional Reliability Standard as submitted, but may not substantively modify the proposed SERC Regional Reliability Standard.

If the SERC Board of Directors chooses to reject a SERC Regional Reliability Standard as submitted, it shall provide its reasons for doing so. The reasons for such decision will be posted on the SERC website. A notice of the posting will be sent to all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to NERC, the regional standards area of the other Regional Entities, individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives. The assigned Standing Committee(s) will determine if the draft standard should be resubmitted with modifications. If so, the draft standard will be remanded back to the RSS in Step 8 above.

Step 13: Submission of SERC Regional Reliability Standards to NERC and FERC

Once the SERC Regional Reliability Standard is approved by the SERC Board of Directors, the SERC President, or the President's designee shall submit the SERC Regional Reliability Standard to NERC for adoption and filing with FERC. The SERC Manager of Reliability Standards will ensure the record of the standard development and any other documentation required for consideration by the NERC Board or FERC are included in the submittal.

If the NERC Board rejects the SERC Regional Reliability Standard the SERC Board will determine if the SERC Regional Reliability Standard is to be sent back to the assigned SERC Standing Committee(s) to incorporate the NERC Board comments or to withdraw the standard.

When adopted by the NERC Board, NERC will submit the SERC Regional Reliability Standard to FERC for approval. If FERC rejects the SERC Regional Reliability Standard, the SERC Board will determine if the SERC Regional Reliability Standard is to be sent back to the assigned SERC Standing Committee(s) to incorporate the FERC comments or to withdraw the standard.

Step 14: Implementation of SERC Regional Reliability Standards

A SERC Regional Reliability Standard that is approved by the SERC Board of Directors, NERC, and FERC, shall become effective on a date designated by FERC. In developing the standard, the RSS should consider the time needed for NERC and FERC approval in the proposed implementation date.

Appendix A: Stakeholder Representation

A.1 SERC Standing Committees and Member Representation

Membership in SERC is open to any entity in the SERC Region that is a user, owner or operator of the Bulk Electric System and subject to the jurisdiction of the Federal Energy Regulatory Commission for the purpose of complying with Reliability Standards established under Section 215 of the Federal Power Act and all amendments thereto. SERC permits full and fair participation of all Member Companies through their representatives, including in the development of and voting on Regional Reliability Standards. The SERC standing committees have a role in developing standards, a ballot pool of the SERC Registered Ballot Body vote to approve Regional Reliability Standards, and the SERC Board of Directors adopts all standards. Since each Member Company is entitled to representation on both the Board and the Standing Committees, SERC's membership policy permits full and fair participation of its Member Companies.

The Standing Committees and their voting rights shall be established pursuant to the SERC Bylaws. Refer to the committee scope documents and the Organization and Procedures Manual for SERC Standing Committees for more specific details.

A.2 SERC Regional Reliability Standards Voting Procedures

The following are the voting procedures for the SERC Registered Ballot Body:

1. Registration Procedures

The Registered Ballot Body (RBB) comprises all organizations and entities that:

- Qualify for one of the SERC Sectors, and
- Are registered with SERC as potential ballot participants in the voting on standards.

All registrations will be done electronically. Each participant, when initially registering to join the RBB will self-select to belong to one of the Sectors and will also name their RBB representative. The Executive Committee of the Board of Directors or its designee will review all applications for joining the Registered Ballot Body, and make a determination of whether the self-selection satisfies the criteria to belong to that sector.

All registered organizations and entities that qualify for a Sector with SERC may vote on a standard. Voting is in writing with each registered stakeholder (a "stakeholder") having one vote. The stakeholder's RBB representative will have the right to register to participate in ballot pools and cast the stakeholder's vote.

2. Sector Qualification Guidelines

The sector qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the SERC Bulk Electric System that can meet the

criteria for a sector as defined in the SERC's Bylaws is entitled to belong to and vote in that sector. The general guidelines are:

- Corporations or organizations with affiliates that qualify to belong to more than one sector (e.g., Investor-Owned Utility and Merchant Electricity Generator) may belong to each of the sectors in which they qualify, provided that each sector is represented by a different representative.
- At any given time, affiliated entities may collectively be registered only once within a sector.
- Any individual currently employed by an organization that is eligible to join one of the other seven sectors, shall not be qualified to join as a "customer" in the ISO-RTO/Customer sector.

3. Definitions

Individual Vote – shall mean a single vote accorded to each stakeholder.

4. Quorum

Two-thirds of the Individual Votes of the Ballot Pool shall constitute a quorum.

5. SERC Registered Ballot Body Voting Requirements

A ballot pool will be established to participate in the ballot of any proposed standards action. Approval of a reliability standard or revision to a reliability standard requires the affirmative vote of a two thirds majority of the weighted Sector votes cast. The number of votes cast in each Sector is the sum of affirmative and negative votes, excluding abstentions and non-response.

The following process is used to determine if there are sufficient affirmative votes.

- The number of affirmative votes cast in each Sector will be divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for each Sector. Abstentions and non-responses will not be counted for the purposes of determining the fractional affirmative vote for a Sector.
- The fractional affirmative vote for a Sector is then multiplied by the Sector weight factor, to determine the weighted fractional affirmative vote for a Sector. The weight factors for the Sectors are:
  - Investor-Owned Utility Sector: weight factor is 3.
  - Federal/State Sector: weight factor is 2.
  - Cooperative Sector: weight factor is 2.
  - Municipal Sector: weight factor is 2.
  - Marketer Sector: weight factor is 1.
  - Merchant Electricity Generator Sector: weight factor is 1.
  - ISO-RTO/Customer Sector: weight factor is 1.

- The sum of the weighted fractional affirmative votes from all Sectors divided by the sum of the weights of the Sectors voting will be used to determine if a two-thirds majority has been achieved. (A Sector will be considered as "voting" if any member of the Sector in the ballot pool casts either an affirmative or a negative vote.)
- A standard will be approved if the sum of weighted fractional affirmative votes from all Sectors divided by the sum of the weights of the voting Sectors is two-thirds or greater.

Appendix B: Principles, Characteristics, and Special Procedures

Principles

SERC develops regional standards with due consideration of the following principles, in accordance with the steps outlined in this procedure. This procedure has been designed to ensure that any SERC Regional Reliability Standard is technically sound and the technical specifications proposed will achieve a valuable reliability objective.

The SERC Regional Reliability Standards Development Procedure has the following characteristics:

- **Open:** Participation in the development of a SERC Regional Reliability Standard shall be open to all organizations that are directly and materially affected by the SERC Bulk Electric System reliability. There shall be no undue financial barriers to participation. Participation shall not be conditioned upon membership in SERC, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements. Meetings of the Responsible SERC Subgroup assigned to draft a standard shall be open to the SERC Member Companies and others.

- **Balanced:** The SERC Regional Reliability Standards Development Procedure strives to have an appropriate balance of interests and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter.

- **Inclusive:** Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the Bulk Electric System in the SERC Region shall have a right to participate by: a) expressing a position and its basis, b) having that position considered, c) registering as a potential ballot participant and voting on a proposed standard; and d) having the right to appeal**.**

- **Fair due process:** The SERC Regional Reliability Standards Development Procedure provides for reasonable notice and opportunity for public comment. This procedure includes public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.

- **Transparent:** All actions material to the development of SERC Regional Reliability Standards shall be transparent. All standards development meetings shall be open and publicly noticed on the SERC Web site.

- **Due Course:** Does not unnecessarily delay development of the proposed SERC Regional Reliability Standard.

NERC has adopted reliability principles and market interface principles to define the purpose, scope, and nature of reliability standards. These principles are to be used to guide the development of reliability standards, including regional reliability standards. The NERC Board of Trustees may modify these principles from time to time, as necessary, to adapt its vision for reliability standards.

- Each SERC Regional Reliability Standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional Bulk Electric System. Each standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

- While reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. Reliability is a necessity for electricity markets, and robust electricity markets can support reliability. Recognizing that Bulk Electric System reliability and electricity markets are inseparable and mutually interdependent, all SERC Regional Reliability Standards shall be consistent with NERC's market interface principles. Consideration of the market interface principles is intended to ensure that standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

Regional Reliability Standard Characteristics and Elements

Characteristics of a SERC Regional Reliability Standard

The following characteristics describe objectives to be considered in the development of SERC Regional Reliability Standards:

1. **Applicability**: Each SERC Regional Reliability Standard clearly identifies the functional classes of entities responsible for complying with the standard, with any specific additions or exceptions noted. Such functional classes include: reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange coordinators, transmission service providers, planning coordinators, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each SERC Regional Reliability Standard identifies the geographic applicability of the standard. A standard may also identify any limitations on the applicability of the standard based on electric facility characteristics.

2. **Reliability Objectives**: Each SERC Regional Reliability Standard has a clear statement of purpose that describes how the standard contributes to the reliability of the Bulk Electric System.

3. **Requirement or Outcome**: Each SERC Regional Reliability Standard states one or

more requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Electric System, consistent with good utility practices and the public interest.

4. **Measurability**: Each performance requirement is stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Each performance requirement has one or more associated measures used to objectively evaluate compliance with the requirement. If performance can be practically measured quantitatively, metrics are provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations**: Each regional reliability standard is based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness**: Each SERC Regional Reliability Standard is complete and self-contained. Supporting references may be provided with standards, but they are not part of the standard and do not impose mandatory requirements.

7. **Clear Language**: Each SERC Regional Reliability Standard is stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practice, are able to arrive at a consistent understanding of the required performance.

8. **Practicality**: Each SERC Regional Reliability Standard establishes requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

9. **Consistent Terminology:** To the extent possible, SERC Regional Reliability Standards use a set of standard terms and definitions that are approved through the SERC Regional Reliability Standard Development Procedure.

Although regional reliability standards have a common format and process, several types of standards may exist, each with a different approach to measurement:

- Technical standards are related to the provision, maintenance, operation, or state of electric systems, and will likely contain measures of physical parameters that are technical in nature.

- Performance standards are related to the actions of entities providing for or impacting the reliability of the Bulk Electric System, and will likely contain measures of the results of such actions or qualities of performance of such actions.

- Preparedness standards are related to the actions of entities to be prepared for conditions that are unlikely to occur, but are nonetheless critical to reliability, and will likely contain measures of such preparations or the state of preparedness.

Elements of a SERC Regional Reliability Standard

To ensure uniformity of SERC Regional Reliability Standards, a SERC Regional Reliability Standard shall consist of the elements identified in Appendix D of this procedure. However, the most current version of the approved NERC Reliability Standard template and its associated elements posted on the NERC website will be used at the time of the development of the SERC Regional Reliability Standard if different from the elements listed in Appendix D. This is to ensure all essential elements are contained in the SERC standard to achieve consistency and uniformity and meet all statutory requirements. These elements are intended to apply a systematic discipline in the development and revision of standards. This discipline is necessary to achieving standards that are measurable, enforceable, and consistent.

All mandatory requirements of a SERC Regional Reliability Standard shall be within the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself.

Maintenance of the SERC Regional Reliability Standards Development Procedure

Any Member Company of SERC, or group (or member of a group) within SERC (i.e., committee, subcommittee, working group, study group, task force, or SERC staff), or any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System may submit a written request to modify the SERC Regional Reliability Standard Development Procedure. The Manager of Reliability Standards shall oversee the handling of the request.

Significant changes to this procedure shall be addressed using the same procedure as a request to develop, modify, or withdraw a SERC Regional Reliability Standard. For any such changes to this procedure, the SERC Standards Committee will assume the responsibilities normally assigned to the Executive Committee(s) of the SERC Standing Committee(s) in Steps 3, 5, and 10.

For any minor changes to this procedure, the SERC Standards Committee shall review the request and submit recommendations to the SERC Board of Directors for consideration. The SERC Board of Directors, on its own motion, may amend the SERC Regional Reliability Standard Procedure.

Maintenance of SERC Regional Reliability Standards

Each SERC Regional Reliability Standard shall be reviewed at least once every five (5) years. The review date will be determined from the effective date or the latest revision date, whichever is later. The review process shall be conducted in accordance with Steps 1 through 14 of the SERC Regional Reliability Standard Development Procedure. As a result of this review, a SERC Regional Reliability Standard shall be reaffirmed, revised, or withdrawn.

Interpretations of Standards

Any Member Company of SERC, or group within SERC, or an entity that is directly and materially affected by reliability of the SERC Bulk Electric System shall be permitted to request an interpretation of a SERC Regional Reliability Standard. The entity requesting an interpretation shall send a request to regstd@serc1.org explaining the specific circumstances surrounding the request and what clarifications are required as applied to those circumstances. The request should indicate the material impact to the requesting party, or others, caused by the lack of clarity or a possible incorrect interpretation. SERC Staff will forward requests for interpretations to the SERC Standards Committee, who will assign an Interpretation Drafting Team (IDT) with the relevant expertise to address the clarification. The IDT should include appropriate industry stakeholder representatives and members of the original Standard Drafting Team, consistent with availability.

As soon as practical [but not more than forty-five (45) calendar days following establishment of the IDT], the IDT will prepare a draft interpretation of the SERC Regional Reliability Standard addressing the issues raised. SERC Staff will post the draft interpretation on the SERC website for 30-day informal[1] stakeholder comment period. A notice of the posting will be sent to all SERC Standing Committees representatives and alternates; NERC; the regional standards area of the other Regional Entities; individuals listed as entity contacts in the SERC Compliance Registry; and the SERC Registered Ballot Body representatives by email. Comments shall be submitted electronically by email to regstd@serc1.org. All comments are due by the close of business on the 30th calendar day of posting. If the comment due date falls on a weekend or nationally recognized holiday, the comments shall be due by the close of business on the next regularly scheduled business day.

The IDT will review the stakeholder feedback and may revise the draft interpretation. The IDT will then forward the draft interpretation to the SERC Standards Committee for review. The Standards Committee will determine if the interpretation is consistent with the standard and does not add additional requirements to the standard. The interpretation will then be posted for public review and a ballot pool will be formed consistent with the process steps to approve a draft standard as detailed in the body of this procedure. The interpretation is then balloted and, if approved, will be submitted for SERC Board of Directors approval and filing with NERC and FERC.

If approved by FERC, the interpretation is appended to the SERC Regional Reliability Standard and is effective immediately. The interpretation will stand until such time as the SERC Regional Reliability Standard is revised through the normal process, at which time the SERC Regional Reliability Standard will be modified to incorporate the clarifications provided by the interpretation.

[1] An informal comment period does not require the IDT to respond to every stakeholder comment and is only used to make potential changes for the final draft of the interpretation.

Appeals

Any Member Company of SERC or any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System that believes it has been or will be adversely affected by any substantive or procedural action or inaction related to the development, approval, revision, or withdrawal of a SERC Regional Reliability Standard shall have the right to appeal. This appeals process applies only to the SERC Regional Reliability Standards Process as defined in this manual. The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made within thirty (30) calendar days of the date of the action purported to cause the adverse effect. The final decisions of any appeal shall be documented in writing and posted on the SERC Member Company website. A notice of the posting will be sent to all SERC Board of Directors representatives and alternates, and to all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to the regional standards area of the other Regional Entities and to any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants:

Level 1 Appeal

Level 1 is the required first step in this appeals process. The appellant submits to the SERC President a complaint in writing that describes the substantive or procedural action associated with a SERC Regional Reliability Standard or the SERC Regional Reliability Standards Process. The appellant must describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary staff and the SERC Standards Committee, the SERC President, or the President's designee shall prepare a written response addressed to the appellant as soon as practical but not more than forty-five (45) calendar days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response will be made a part of the record associated with the SERC Regional Reliability Standard.

Level 2 Appeal

If after the Level 1 Appeal, the appellant remains unsatisfied with the resolution, notification shall be made in writing to the SERC President within fifteen (15) calendar days of the affected entity's Level 2 Appeal to the SERC Executive Committee. In all cases, no SERC Executive Committee members that have any direct affiliation with the participants in the appeal will participate in the Level 2 Appeal.

SERC Staff shall post on the SERC website the notice of the Level 2 appeal and other relevant materials at least fifteen (15) calendar days prior to consideration of the Level 2 appeal by the SERC Executive Committee.

In addition to the appellant, any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System, and who is directly and materially affected by the substantive or procedural action referenced in the complaint shall be heard by the SERC Executive Committee. The SERC Executive Committee shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal.

The Executive Committee may direct the SERC Standards Committee to research and/or advise it on technical issues or matters related to the appeal. Each appellant, any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System, and who is directly and materially affected by the substantive or procedural action referenced in the complaint may request that an ad-hoc committee be formed to assist the Executive Committee in its review.

The SERC Executive Committee may in its decision find for the appellant and remand the issue to the SERC Standards Committee for resolution with a statement of the issues and facts in regard to which fair and equitable action was not taken.

The SERC Executive Committee may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections.

The actions of the SERC Executive Committee shall be posted on the SERC website. A notice of the posting will be sent to the appellant, all SERC Board of Directors representatives and alternates, and all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to the regional standards area of the other Regional Entities and to any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System.

Appendix C: SERC Regional Reliability Standard Authorization Request Form (Latest approved version of form is posted on the SERC website: www.serc1.org)

SERC to complete

ID
Authorized for Posting
Authorized for Development

Title of Proposed Standard:
Request Date:

SAR Originator Information

Name	**SAR Type** (Check box for one of these selections.)	
Company		New Standard
Telephone		Revision to Existing Standard
Fax		Withdrawal of Existing Standard
E-mail	---	----------

Purpose (Describe the purpose of the proposed Standard — what the Standard will achieve in support of reliability.)

Industry Need (Provide a detailed statement justifying the need for the proposed Standard, along with any supporting documentation.)

For Example Only

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

Justification (Provide a detailed statement justifying the need for the proposed standard.)

Reliability Functions

The Standard May Apply to the Following Functions (Check box for each one that applies.)

	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
	Transmission Owner	Owns and maintains transmission facilities.
	Transmission Operator	Ensures the Real-time operating reliability of the transmission assets within a Transmission Operator Area.
	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.

For Example Only

	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
	Generator Operator	Operates generation unit(s) to provide real and reactive power.
	Generator Owner	Owns and maintains generation facilities.
	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
	Distribution Provider	Delivers electrical energy to the End-use customer.
	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

NOTE: The RSS may find it necessary to modify the initial reliability function responsibility assignment as a result of the standards development and comments received.

Applicable Reliability Principles *(Check all boxes that apply.)*	
☐	1. Interconnected Bulk Electric Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected Bulk Electric Systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected Bulk Electric Systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected Bulk Electric Systems shall be developed, coordinated, maintained, and implemented.
☐	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected Bulk Electric Systems.
☐	6. Personnel responsible for planning and operating interconnected Bulk Electric Systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected Bulk Electric Systems shall be assessed, monitored, and maintained on a wide-area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
Recognizing that reliability is an Common Attribute of a robust North American economy:	
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes	

For Example Only

2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description *(*Provide enough detail so that an independent entity familiar with the industry could draft a Standard based on this description.*)*

Related Reliability Standards (NERC and SERC Regional)

Standard No.	Explanation

Related SARs

SAR ID	Explanation

For Example Only

Implementation Plan

Description *(Provide plans for the implementation of the proposed standard, including any known systems or training requirements. Include the reliability risk(s) associated with the violation that the standard will mitigate, and the costs associated with implementation.)*
Proposed Implementation days after Board of Directors approval or **on (date):**

For Example Only

Appendix D: Elements of a SERC Regional Reliability Standard

Title	A brief, descriptive phrase identifying the topic of the standard.
Identification Number	A unique identification number assigned to facilitate tracking and reference to SERC Regional Reliability Standards. The identification number will be consistent with the Numbering Convention for NERC Regional Reliability Standards. The latest approved version of the convention will be posted on the SERC website (www.serc1.org).
Effective Date and Status	The effective date of the standard or, prior to approval of the standard by the Board of Directors, the proposed effective date.
Purpose	The purpose of the standard. The purpose shall explicitly state what outcome is expected by this standard.
Applicability	Clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions. If not applicable to the entire SERC Region, then a clear identification of the portion of the Bulk Electric System to which the standard applies. Any limitation on the applicability of the standard based on electric facility requirements should be described.
Requirement(s)	Explicitly stated technical, performance, and preparedness requirements. Each requirement identifies what entity is responsible and what action is to be performed or what outcome is to be achieved. Each statement in the requirements section shall be a statement for which compliance is mandatory.
Violation Severity Levels	Defines the degree to which compliance with a requirement was not achieved. Each requirement must have at least one Violation Severity Level.

Violation Risk Factor(s)	The potential reliability significance of each requirement, designated as a High, Medium, or Lower Risk Factor in accordance with the criteria listed below: A High Risk Factor requirement (a) is one that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or (b) is a requirement in a planning timeframe that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to abnormal condition. A Medium Risk Factor requirement (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System, but is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or (b) is a requirement in a planning timeframe that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition. A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

Measure(s)	Each requirement shall be addressed by one or more measurements. Measurements that will be used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measurement identifies to whom the measurement applies and the expected level of performance or outcomes required demonstrating compliance. Each measurement shall be tangible, practical, and as objective as is practical. It is important to realize that measures are proxies to assess required performance or outcomes. Achieving the full compliance level of each measurement should be a necessary and sufficient indicator that the requirement was met. Each measure shall clearly refer to the requirement(s) to which it applies.
Compliance Monitoring Process	Defines for each measure: • The specific data or information that is required to measure performance or outcomes. • The entity that is responsible for providing the data or information for measuring performance or outcomes. • The process that will be used to evaluate data or information for the purpose of assessing performance or outcomes. • The entity that is responsible for evaluating data or information to assess performance or outcomes. • Measurement data retention requirements and assignment of responsibility for data archiving.
Time Horizon	The time period an entity has to mitigate an instance of violating the associated requirement. • Long-term Planning — a planning horizon of one year or longer. • Operations Planning — operating and resource plans from day-ahead up to and including seasonal. • Same-day Operations — routine actions required within the timeframe of a day, but not real-time. • Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system. • Operations Assessment — follow-up evaluations and reporting of real time operations.

Attached Supporting Information Elements

Interpretations	Any interpretations of the SERC Regional Reliability Standards that were developed, and approved by the SERC Executive Committee, to expound on the application of the standard for unusual or unique situations.
Implementation Plan	Each SERC Regional Reliability Standard shall have an associated implementation plan describing the effective date of the standard or effective dates if there is a phased implementation. The implementation plan may also describe the implementation of the standard in the compliance program and other considerations in the initial use of the standard, such as necessary tools, training, etc. The implementation plan must be posted for at least one public comment period and is approved as part of the ballot of the standard.
Supporting References	This section references related documents that support reasons for, or otherwise provide additional information related to the standard Examples include, but are not limited to: • Glossary of Terms • Developmental history of the standard and prior versions • Responsible SERC Subgroup • Notes pertaining to implementation or compliance • Standard references • Procedures/Practices • Training and/or Technical Reference • Frequently Asked Questions Document

Appendix E: Comment Form for Draft SERC Regional Reliability Standard (Latest approved version of form is posted on the SERC website: www.serc1.org)

COMMENT FORM FOR [INSERT APPROPRIATE TITLE OF SERC REGIONAL RELIABILITY STANDARD]

Please use this form to submit comments on **[insert description]**. Comments must be submitted by **[date].** You must submit the completed form by emailing it to **[insert appropriate contact names & e-mail addresses]** with the words **[insert appropriate subject]** in the subject line. If you have questions please contact **[insert appropriate contact names, e-mail addresses & phone numbers]**.

DO: **Do** use punctuation and capitalization as needed.
Do use more than one form if responses do not fit in the spaces provided.
Do submit any formatted text or markups in a separate WORD file.

DO NOT: **Do not** submit a response in an unprotected copy of this form.

Commenter Information
Group Name (if applicable):
Contact Name:
Organization:
Telephone:
Email:

Background:

In this section, provide background information including the reasons for the development of new SERC Regional Reliability Standard or revisions to an existing SERC Regional Reliability Standard.

Major Changes to this Revision of the SERC Regional Reliability Standard

Provide additional information that may help the reviewers better understand the need and motivation for the changes.

Include any other sections as necessary to facilitate the review process.

For Example Only

Please Enter All Comments in Simple Text Format.

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

[The following are sample questions. Revise the questions as appropriate.]

1. Do you agree with the inclusion of the following in section [xxx] of the standard?

   Describe revision details.

   ☐ Yes

   ☐ No

   ☐ Comments:

2. Do you agree with the proposed definitions that were added or revised?

   ☐ Yes

   ☐ No

   ☐ Comments:

3. Do you agree with the deletion of the following section from part [xxx]?

   ☐ Yes

   ☐ No

   ☐ Comments:

4. Do you agree with the proposed changes in section [xxx] of the document?

   ☐ Yes

   ☐ No

   ☐ Comments:

5. Please identify anything you believe needs to be modified before this revision of the standard can be approved by SERC?

   ☐ Comments:

6. Please provide any other comments on this revision of the standard?

   ☐ Comments:

For Example Only

Appendix F: SERC Consideration of Comments Form (Latest approved version of form is posted on the SERC website: www.serc1.org)

SERC [INSERT RSS NAME] Consideration of Comments on
[INSERT APPROPRIATE SERC REGIONAL RELIABILITY STANDARD TITLE & REV. #]

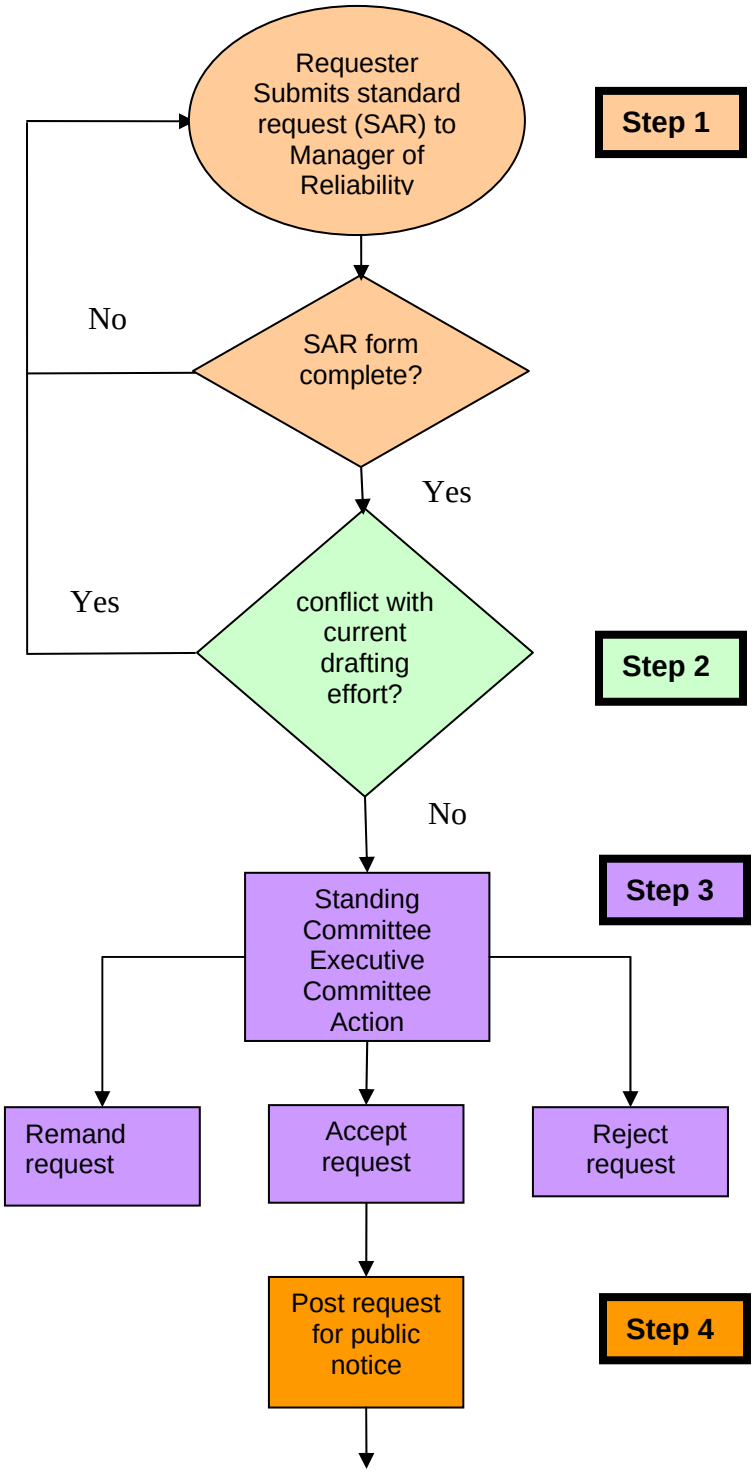
[SAMPLE LANGUAGE]
This document contains comments submitted on Revision [_] of the [Standard], which was distributed for review on [Date] in accordance with the SERC Regional Reliability Standards Process Manual. Comments were received from the following.

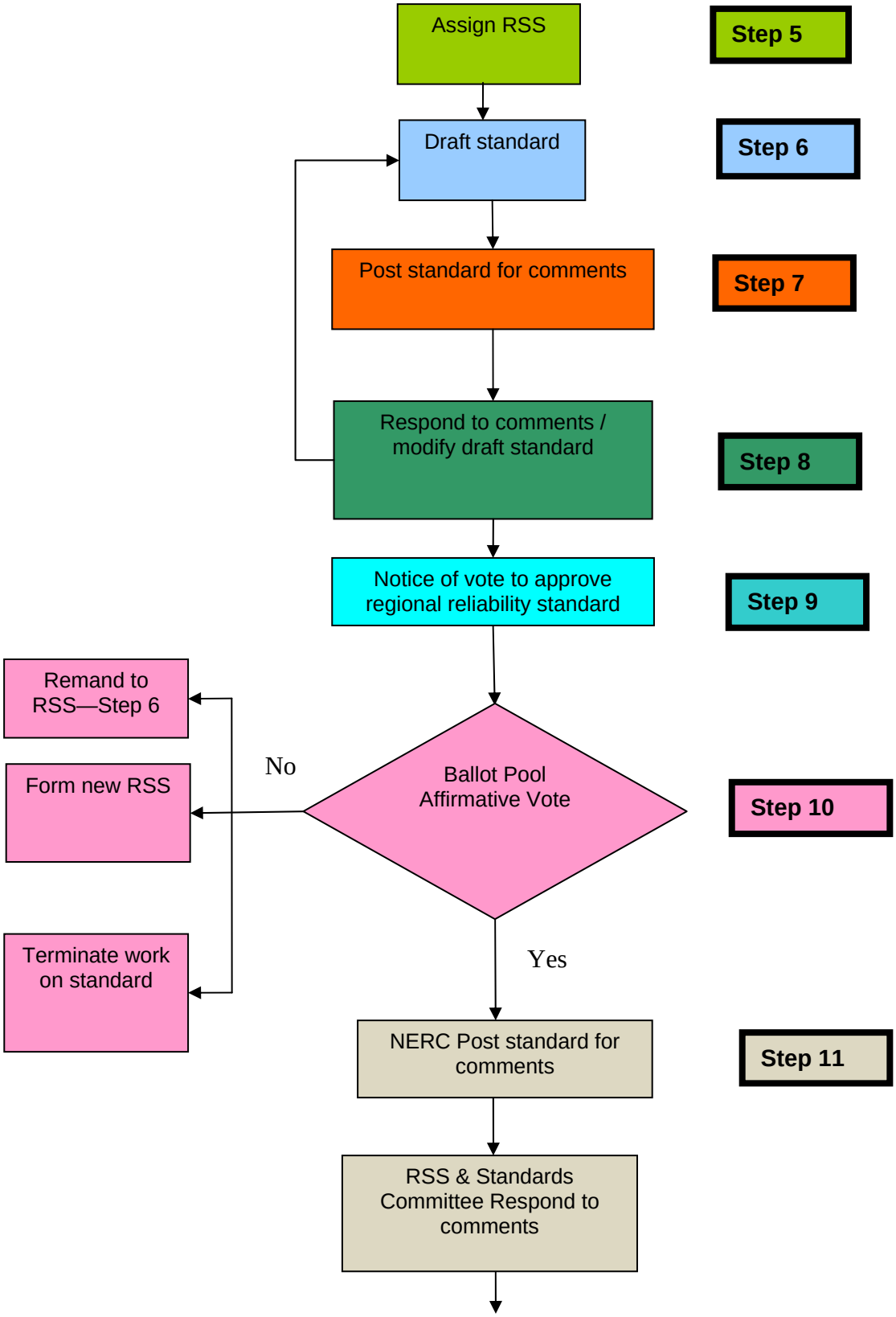
[INSERT INTRODUCTORY LANGUAGE AS APPROPRIATE]

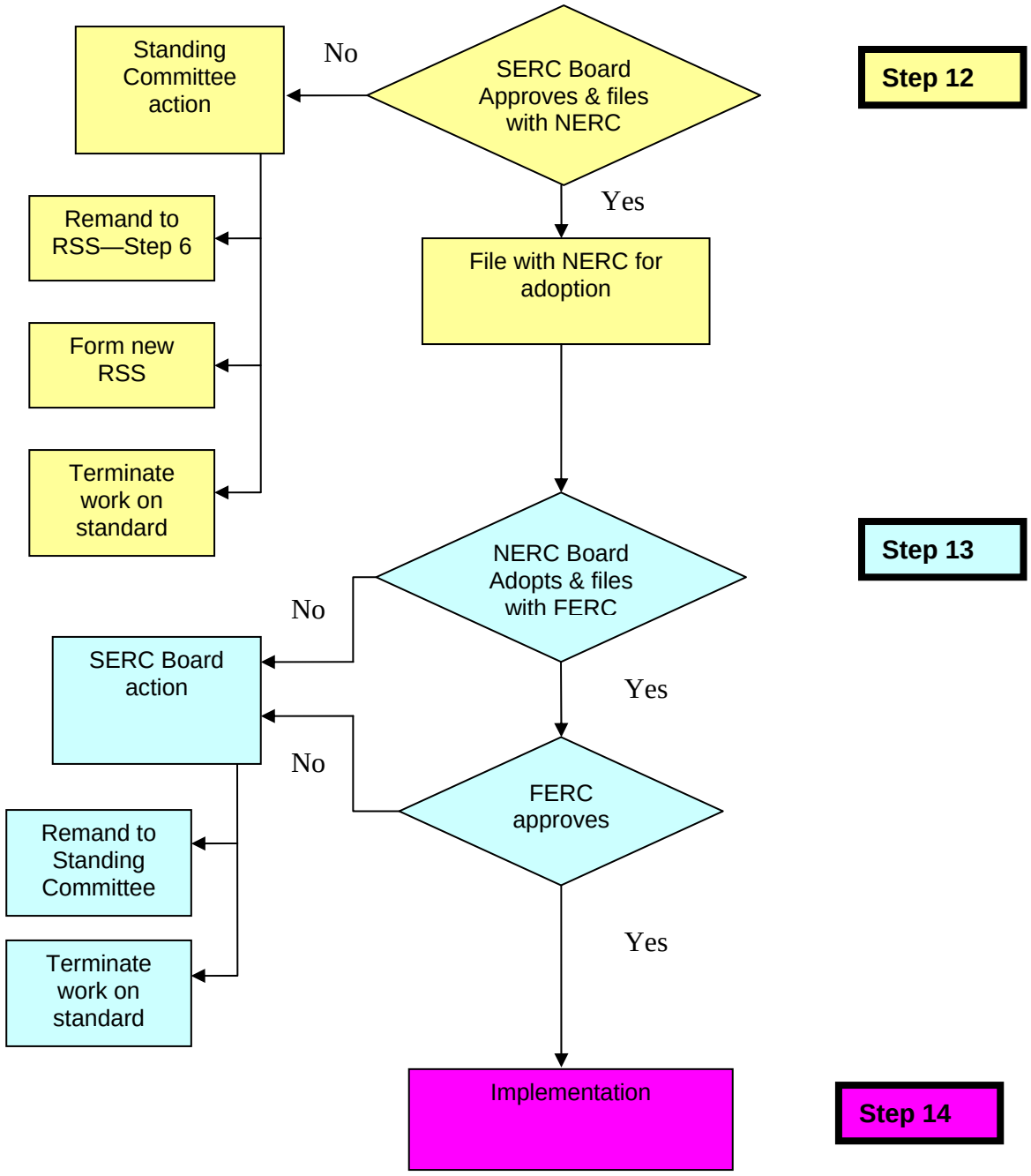
Commenter	Comment	Response

For Example Only

Appendix G: SERC Process Flow Diagram




Assign RSS
Step 5
Draft standard
Step 6
Post standard for comments
Step 7
Respond to comments / modify draft standard
Step 8
Notice of vote to approve regional reliability standard
Step 9
Remand to RSS—Step 6
No
Form new RSS
Ballot Pool Affirmative Vote
Step 10
Terminate work on standard
Yes
NERC Post standard for comments
Step 11
RSS & Standards Committee Respond to comments


Standing Committee action
No
SERC Board Approves & files with NERC
Step 12
Yes
Remand to RSS—Step 6
File with NERC for adoption
Form new RSS
Terminate work on standard
NERC Board Adopts & files with FERC
Step 13
No
SERC Board action
Yes
No
FERC approves
Remand to Standing Committee
Terminate work on standard
Yes
Implementation
Step 14

Proposed Revision 2

SERC Regional Standards Development Procedure

Exhibit C
to the
Amended and Restated
Regional Entity Delegation Agreement
between

North American Electric Reliability Corporation
and
SERC Reliability Corporation

Exhibit C – Regional Standard Development Procedure

Exhibit C sets forth SERC Reliability Corporation's standards development procedure, which NERC agrees meets the following common attributes:

COMMON ATTRIBUTE 1

Proposed regional reliability standards shall be subject to approval by NERC, as the electric reliability organization, and by FERC before becoming mandatory and enforceable under Section 215 of the FPA [add reference to any applicable authorities in Canada and Mexico]. No regional reliability standard shall be effective within the [Regional Entity Name] area unless filed by NERC with FERC [and applicable authorities in Canada and Mexico] and approved by FERC [and applicable authorities in Canada and Mexico].

COMMON ATTRIBUTE 2

[Regional Entity Name] regional reliability standards shall provide for as much uniformity as possible with reliability standards across the interconnected bulk power system of the North American continent. A [Regional Entity Name] reliability standard shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or shall be a regional difference necessitated by a physical difference in the bulk power system. A regional reliability standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.

COMMON ATTRIBUTE 3

[Regional Entity Name] regional reliability standards, when approved by FERC [add applicable authorities in Canada], shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable bulk power system owners, operators, and users within the [Regional Entity Name] area, regardless of membership in the region.

COMMON ATTRIBUTE 4

Requester — The requester is the sponsor of the regional reliability standard request may assist in the development of the standard. Any member of [Regional Entity Name], or group within [Regional Entity Name] shall be allowed to request that a regional reliability standard be developed, modified, or

withdrawn. Additionally, any entity (person, organization, company, government agency, individual, etc.) that is directly and materially affected by the reliability of the bulk power system in the [Regional Entity Name] area shall be allowed to request a regional reliability standard be developed, modified, or withdrawn.

COMMON ATTRIBUTE 5

[Standards or other named] committee — The [Regional Entity Name] [standards] committee manages the standards development process. The [standards] committee will consider which requests for new or revised standards shall be assigned for development (or existing standards considered for deletion). The [standards] committee will advise the [Regional Entity Name] board on standards presented for adoption.

COMMON ATTRIBUTE 6A [REGISTERED BALLOT BODY APPROACH]

The registered ballot body comprises all entities or individuals that qualify for one of the stakeholder segments; are registered with [Regional Entity Name] as potential ballot participants in the voting on standards; and are current with any designated fees. Each member of the registered ballot body is eligible to vote on standards. [Each standard action has its own ballot pool formed of interested members of the registered ballot body. Each ballot pool comprises those members of the registered ballot body that respond to a pre-ballot survey for that particular standard action indicating their desire to participate in such a ballot pool.] The representation model of the registered ballot body is provided in Appendix A.]

COMMON ATTRIBUTE 7

[Regional Entity Name] will coordinate with NERC such that the acknowledgement of receipt of a standard request identified in step 1, [SERC Step 4], notice of comment posting period identified in step 4, [SERC Step 7], and notice for vote identified in step 5 [SERC Step 9] below are concurrently posted on both the [Regional Entity Name] and NERC websites.

COMMON ATTRIBUTE 8

An acceptable standard request shall contain a description of the proposed regional reliability standard subject matter containing sufficiently descriptive detail to clearly define the purpose, scope, impacted parties, and other relevant information of the proposed standard.

COMMON ATTRIBUTE 9

Within [no greater than 60] days of receipt of a completed standard request, the [standards] committee shall determine the disposition of the standard request.

COMMON ATTRIBUTE 10

The [standards] committee may take one of the following actions:

- Accept the standard request as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The [standards] committee may, at its discretion, expand or narrow the scope of the standard request under consideration. The [standards] committee shall prioritize the development of standard in relation to other proposed standards, as may be required based on the volume of requests and resources.
- Reject the standard request. If the [standards] committee rejects a standard request, a written explanation for rejection will be delivered to the requester within [no greater than 30] days of the decision.
- Remand the standard request back to the requester for additional work. The standards process manager will make reasonable efforts to assist the requester in addressing the deficiencies identified by the [standards] committee. The requester may then resubmit the modified standard request using the process above. The requester may choose to withdraw the standard request from further consideration prior to acceptance by the [standards] committee.

COMMON ATTRIBUTE 11

Any standard request that is accepted by the [standards] committee for development of a standard (or modification or deletion of an existing standard) shall be posted for public viewing on the [Regional Entity Name] website within [no greater than 30] days of acceptance by the committee.

COMMON ATTRIBUTE 12

The standards process manager shall submit the proposed members of the drafting team to the [standards] committee. The [standards] committee shall approve the drafting team membership within 60 days of accepting a standard request for development, modifying the recommendations of the standards process manager as the committee deems appropriate, and assign development of the proposed standard to the drafting team.

COMMON ATTRIBUTE 13

At the direction from the [standards] committee, the standards process manager shall facilitate the posting of the draft standard on the [Regional Entity Name] website, along with a draft implementation plan and supporting documents, for a no less than a [30]-day] comment period. The standards process manager shall provide notice to [Regional Entity Name] stakeholders and other potentially interested entities, both within and outside of the [Regional Entity Name] area, of

the posting using communication procedures then currently in effect or by other means as deemed appropriate.

COMMON ATTRIBUTE 14

The drafting team shall prepare a summary of the comments received and the changes made to the proposed standard as a result of these comments. The drafting team shall summarize comments that were rejected by the drafting team and the reason(s) that these comments were rejected, in part or whole. The summary, along with a response to each comment received will be posted on the [Regional Entity Name] website no later than the next posting of the proposed standard.

COMMON ATTRIBUTE 15

Upon recommendation of the drafting team, and if the [standards] committee concurs that all of the requirements for development of the standard have been met, the standards process manager shall post the proposed standard and implementation plan for ballot and shall announce the vote to approve the standard, including when the vote will be conducted and the method for voting. Once the notice for a vote has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

COMMON ATTRIBUTE 16

The standards process manager shall schedule a vote by the [Regional Entity Name] [registered ballot body/[standards] committee]. The vote shall commence no sooner than [15] days and no later than [30] days following the issuance of the notice for the vote.

COMMON ATTRIBUTE 17

The [standards] committee shall give due consideration to the work of the drafting team, as well as the comments of stakeholders and minority objections, in approving a proposed regional reliability standard for submittal to the [Regional Entity Name] board. The [standards] committee may vote to approve or not approve the standard. Alternatively, the [standards] committee may remand the standard to the drafting team for further work or form a new drafting team for that purpose.

COMMON ATTRIBUTE 18

The [standards] committee may not itself modify the standard without issuing a new notice to stakeholders regarding a vote of the modified standard.

COMMON ATTRIBUTE 19

Actions by the committee shall be recorded in the regular minutes of the committee.

COMMON ATTRIBUTE 20

Under no circumstances may the board substantively modify the proposed regional reliability standard.

COMMON ATTRIBUTE 21

Once a regional reliability standard is approved by the board, the standard will be submitted to NERC for approval and filing with FERC [and applicable authorities in Canada and Mexico.]

COMMON ATTRIBUTE 22

Open - Participation in the development of a regional reliability standard shall be open to all organizations that are directly and materially affected by the [Regional Entity Name] bulk power system reliability. There shall be no undue financial barriers to participation. Participation shall not be conditioned upon membership in [Regional Entity Name], and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements. Meetings of drafting teams shall be open to the [Regional Entity Name] members and others.

COMMON ATTRIBUTE 23

Balanced - The [Regional Entity Name] standards development process strives to have an appropriate balance of interests and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter.

COMMON ATTRIBUTE 24

Inclusive — Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the bulk power system in the [Regional Entity Name] area shall have a right to participate by: a) expressing a position and its basis, b) having that position considered, and c) having the right to appeal.

COMMON ATTRIBUTE 25

Fair due process — The regional reliability standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the procedure shall include public notice of the intent to develop a

standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.

COMMON ATTRIBUTE 26

Transparent — All actions material to the development of regional reliability standards shall be transparent. All standards development meetings shall be open and publicly noticed on the regional entity's Web site.

COMMON ATTRIBUTE 27

Does not unnecessarily delay development of the proposed reliability standard.

COMMON ATTRIBUTE 28

Each standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk power system. Each standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

COMMON ATTRIBUTE 29

While reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. Reliability is a necessity for electricity markets, and robust electricity markets can support reliability. Recognizing that bulk power system reliability and electricity markets are inseparable and mutually interdependent, all regional reliability standards shall be consistent with NERC's market interface principles. Consideration of the market interface principles is intended to ensure that standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

COMMON ATTRIBUTE 30

To ensure uniformity of regional reliability standards, a regional reliability standard shall consist of the elements identified in this section of the procedure. These elements are intended to apply a systematic discipline in the development and revision of standards. This discipline is necessary to achieving standards that are measurable, enforceable, and consistent.

COMMON ATTRIBUTE 31

All mandatory requirements of a regional reliability standard shall be within the standard. Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself.

COMMON ATTRIBUTE 32

Clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions.

If not applicable to the entire [Regional Entity Name] area, then a clear identification of the portion of the bulk power system to which the standard applies. Any limitation on the applicability of the standard based on electric facility requirements should be described.

COMMON ATTRIBUTE 33

Each requirement shall be addressed by one or more measures. Measures are used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measure will identify to whom the measure applies and the expected level of performance or outcomes required demonstrating compliance. Each measure shall be tangible, practical, and as objective as is practical. It is important to realize that measures are proxies to assess required performance or outcomes. Achieving the measure should be a necessary and sufficient indicator that the requirement was met. Each measure shall clearly refer to the requirement(s) to which it applies.

COMMON ATTRIBUTE 34

Defines for each measure:

- The specific data or information that is required to measure performance or outcomes.
- The entity that is responsible for providing the data or information for measuring performance or outcomes.
- The process that will be used to evaluate data or information for the purpose of assessing performance or outcomes.
- The entity that is responsible for evaluating data or information to assess performance or outcomes.
- The time period in which performance or outcomes is measured, evaluated, and then reset.
- Measurement data retention requirements and assignment of responsibility for data archiving.
- Violation severity levels.

Revision History

Revision	Date	Comments
0	October 25, 2006	Document Origination
1	October 10, 2007	Document revised to change to a registered ballot body approach to approve standards, changed "Manager of Reliability Services" to Manager of Reliability Standards," changed the RSS meeting notice period to 21 days, changed the review period for this procedure from five to three years, and moved from the Standing Committee Executive Committees to the SERC Standards Committee the ability to remand a SAR back to the Requester for additional work.
2	Ballot Pool approved: September 29, 2011	Update to 1) address document Three-Year Review and Re-Approval Requirements; 2) address issues identified during the SERC 2009 audit by NERC; 3) make revisions to improve process efficiency and reduce the time required to develop a regional standard; 4) ensure alignment with the NERC Standard Processes Manual, Revision 1 dated November 2010; and 5) changed the review period for this procedure back from three to five years..

Responsible SERC Group(s)

SERC Standards Committee (SC)

Review and Re-Approval Requirements

This document will be reviewed every ~~three~~five years or as appropriate by the SERC Standards Committee for possible revision~~. The existing or revised document will be re-certified and distributed to all members of SERC.~~

List of Appendices

Appendix A: ~~-~~Stakeholder Representation
Appendix B: ~~-~~Principles, Characteristics, and Special Procedures
Appendix C: ~~-~~SERC Regional Reliability Standard Authorization Request Form
Appendix D: ~~-~~Elements of a SERC Regional Reliability Standard
Appendix E:~~–~~ Comment Form for Draft SERC Regional Reliability Standard
Appendix F:~~–~~ SERC Consideration of Comments Form
Appendix G:~~–~~ SERC Process Flow Diagram

Introduction

This procedure defines the process for development, revision, reaffirmation, and withdrawal of a regional reliability standard by the SERC Reliability Corporation (SERC). SERC is a regional entity authorized through an approved delegation agreement with the North American Electric Reliability Corporation (NERC) to propose regional reliability standards in accordance with Section 215 of the Federal Power Act (FPA), the U.S. Federal Energy Regulatory Commission (FERC) Order No. 672, and Section 39 of Title 18 ~~§ 39~~ of the U.S. Code of Federal Regulations (18 C.F.R. ~~18~~ § 39).

SERC Regional Reliability Standards apply to the planning, operation, and critical infrastructure protection of the Bulk ~~Power~~Electric System in the SERC Region. Proposed SERC Regional Reliability Standards shall be subject to approval by NERC, as the electric reliability organization, and by FERC before becoming mandatory and enforceable under Section 215 of the FPA. ~~-~~No SERC Regional Reliability Standard shall be effective within the SERC ~~area~~ Regon unless filed by NERC with FERC and approved by FERC.

SERC Regional Reliability Standards shall provide for as much uniformity as possible with reliability standards across the interconnected ~~bulk power system~~Bulk Electric System of the North American continent.~~-~~ A SERC Regional Reliability Standard shall be more stringent than a continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide reliability standard does not, or regional difference necessitated by a physical difference in the ~~bulk power system.~~ Bulk Electric System. A SERC Regional Reliability Standard that satisfies the statutory and regulatory criteria for approval of proposed North American reliability standards, and that is more stringent than a continent-wide reliability standard, would generally be acceptable.

SERC Regional Reliability Standards, when approved by FERC, shall be made part of the body of NERC reliability standards and shall be enforced upon all applicable ~~bulk power system~~Bulk Electric System owners, operators, and users within the SERC ~~area~~Regon, regardless of membership in the region.

Process Roles

Requester: The requester is the sponsor of the SERC Regional Reliability Standard request and may assist in the development of the standard. Any ~~member~~ Member Company of SERC, or any group (or member of a group) within SERC (i.e., committee, subcommittee, working group, study group, task force, or SERC staff), shall be allowed to request that a SERC Regional Reliability Standard be developed, modified, or withdrawn. Additionally, any entity that is directly and materially affected by the reliability of the SERC Bulk ~~Power~~Electric System shall be allowed to request that a SERC Regional Reliability Standard be developed, modified, or withdrawn.

SERC Board of Directors: The SERC Board of Directors shall consider for ~~adoption~~approval as SERC Regional Reliability Standards, those Standards that have been developed and approved by this procedure. Once the Board ~~adopts~~approves a SERC Regional Reliability Standard, such Standard shall be submitted to NERC for approval. When approved by NERC, it shall be submitted to FERC for approval.

SERC Staff: The SERC Manager of Reliability Standards is responsible for forwarding a request for the development, modification or withdrawal of SERC Regional Reliability Standards to the SERC Standards Committee. The SERC Staff shall facilitate all steps in this process.

SERC Standards Committee: The SERC Regional Reliability Standard Development Procedure shall be administered by the SERC Standards Committee (SC). The SERC SC is responsible for ensuring that the development, modification or withdrawal of SERC Regional Reliability Standards is in accordance with the steps in this procedure. The SERC SC will ensure the integrity of the process and the consistency of quality and completeness of the SERC Regional Reliability Standards.

SERC Standing Committees: The SERC Standing Committees will perform a high level technical review of the SAR to determine which requests for new or revised standards shall be assigned for development (or existing standards considered for deletion). The Standing Committees will appoint the standard drafting team (Responsible SERC Subgroup).

The current SERC Standing Committees are the Engineering Committee (EC), Operating Committee (OC), and Critical Infrastructure Protection Committee (CIPC). The Standing Committees are balanced stakeholder committees, inclusive of all stakeholder interests that provide for or are materially impacted by the reliability of the ~~bulk power system. See Appendix A for the representation model of the Standing Committees.~~Bulk Electric System.

~~**Compliance Advisory Groups**: The SERC Compliance Advisory Groups provide inputs and comments during the standards development process to ensure the measures will be effective and other aspects of the compliance program can be practically implemented.~~

Responsible SERC Subgroup (RSS): Responsible SERC Subgroups are teams, responsible for drafting the standard~~.~~; they are also referred to as the Standard Drafting Team (SDT). The RSS may include technical experts and be based around a permanent SERC Standing Committee subgroup. ~~-~~An RSS is established expressly to draft the standard. Membership on an RSS will be assigned by the SERC EC, OC, and/or CIPC. ~~-~~The requester may act as the RSS, serve on the RSS, or otherwise assist the RSS. SERC membership is not a prerequisite for serving on an RSS. The RSS will:

- Develop the details of the SERC Regional Reliability Standard,
- Consider and respond to industry comments,
- Participate in forums to help build consensus on draft SERC Regional Reliability Standards,
- Assist in the implementation of approved SERC Regional Reliability Standards,
- Provide technical oversight in response to changing industry conditions, and
- Assist in the identification of the need for new SERC Regional Reliability Standards.

Registered Ballot Body (RBB): ~~-~~The registered ballot body votes to approve standards.~~-~~ The RBB comprises all entities or individuals that qualify for one of the SERC industry Sectors, and are registered with SERC as potential ballot participants in the voting on standards. SERC membership is not a prerequisite for registering with SERC as a potential ballot participant. Any entity that is directly and materially affected by the reliability of the SERC Bulk ~~Power~~Electric System shall be allowed to register as a potential ballot participant.

Each member of the registered ballot body is eligible to vote on standards. ~~-~~Each standard action has its own ballot pool formed of interested members of the registered ballot body.

Ballot Pool:~~-~~ Each standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot survey for that particular standard action. The ballot pool will ensure, through its vote, the need for and technical merits of a proposed standard action and the appropriate consideration of views and objections received during the development process. The ballot pool votes to approve each standards action.

Process Steps

Note: The term “days” below refers to calendar days.

SERC will coordinate with NERC such that the acknowledgement of receipt of an accepted standard request identified in ~~step~~Step 4, notice of comment posting period identified in ~~step~~Step 7, and notice for vote identified in ~~step~~Step 9 below are concurrently posted on both the SERC and NERC websites.

Step 1: Request for a new SERC Regional Reliability Standard or modification to, or withdrawal of an existing SERC Regional Reliability Standard

A request to develop, modify or withdraw a SERC Regional Reliability Standard shall be submitted, using the SERC Regional Reliability Standard Authorization Request (SAR) Form (see Appendix C), to the SERC Manager of Reliability Standards (via e-mail to regstd@serc1.org) by any ~~member~~ Member Company of SERC, or any group (or member of a group) within SERC (i.e., committee, subcommittee, working group, study group, task force, or SERC staff), or any entity that is directly and materially affected by reliability of the SERC Bulk ~~Power~~Electric System. The SERC SAR Form can be downloaded from the SERC website (www.serc1.org).

An acceptable SAR shall contain a description of the proposed regional reliability standard subject matter with sufficient descriptive detail of the proposed standard to clearly define the purpose, scope, impacted parties, and other relevant information. The requester must verify in the Justification section of the SAR that the request meets one of the following criteria:

- The proposed standard covers a topic addressed in a continent-wide standard, but the proposed standard will include requirements more stringent than those in the continent-wide standard.
- The proposed standard addresses matters that the continent-wide reliability standards do not.
- The proposed standard is necessitated by a physical difference in the Bulk Electric System.

SERC Staff shall verify that the SAR Form has been adequately completed. Within 15 days of receiving the SAR, the SERC Manager of Reliability Standards or his designee will electronically acknowledge receipt of the SAR, and will forward the SAR to the SERC Standards Committee. The SERC Manager of Reliability Standards may offer the Requester suggestions regarding changes or improvements to enhance the clarity of the proposed standards work and to assist the SERC Standards Committee in

understanding the requester's intent and objectives. The requester is free to accept or reject these suggestions.

Step 2: Assignment of SERC Regional Reliability Standard Request

The SERC Standards Committee will review the SAR to ensure it is not in conflict with or duplication of a current standard or a standards drafting effort already proposed or in progress. Within 15 days after receiving the SAR from the SERC Manager of Reliability Standards, the SERC Standards Committee will take one of the two following actions:

- Assign the SAR to the appropriate SERC Standing Committee(s). SERC Staff will forward the SAR to the Chair(s) and Executive Committee(s) of the appropriate SERC Standing Committee(s) ~~Chair(s) and Standing Committee(s) Executive Committee~~.

- Remand the SAR back to the Requester for additional work. The SERC Manager of Reliability Standards will make reasonable efforts to assist the Requester in addressing the deficiencies identified by the SERC Standards Committee. The Requester may then resubmit the modified SAR using the process above. The requester may choose to withdraw the SAR from further consideration.

Step 3: Acceptance of a SERC Regional Reliability Standard Request

Within 60 days of receipt of a completed SAR, the Executive Committee(s) of the assigned SERC Standing Committee(s) ~~Executive Committee(s)~~ shall determine the disposition of the SAR. The committee(s) shall verify that the SAR requester has provided information to justify that the request meets one of the following criteria:

- The proposed standard covers a topic addressed in a continent-wide standard, but the proposed standard will include requirements more stringent than those in the continent-wide standard.
- The proposed standard addresses matters that the continent-wide reliability standards do not.
- The proposed standard is necessitated by a physical difference in the Bulk Electric System.

The committee may take one of the two following actions:

- Accept the SAR as a candidate for development of a new standard, revision of an existing standard, or deletion of an existing standard. The committee(s) may, at its discretion, expand or narrow the scope of the SAR under consideration. The committee(s) shall prioritize the development of standard in relation to other proposed standards, as may be required based on the volume of requests and resources.

- Reject the SAR. If the committee(s) rejects a SAR, a written explanation for rejection will be delivered to the Requester within 30 days of the decision.

Deliberations and decisions of the Executive Committee(s) of the assigned SERC Standing Committee(s) ~~Executive Committee(s)~~ concerning requests shall be made and documented in accordance with the SERC Standing Committee rules and procedures then in effect.

Step 4: Posting of SERC Regional Reliability Standard Request

Any SAR that is accepted by the Executive Committee(s) of the assigned SERC Standing Committee(s) ~~Executive Committee(s)~~ for development of a standard (or modification or deletion of an existing standard) shall be posted for public viewing on the SERC website within 30 days of acceptance by the committee. A comments form and a nomination form to serve on the drafting team (Responsible SERC Subgroup) will be included in the posting. A notice of the posting for a 30-day comment period will be sent to all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to NERC, the ~~Region Managers~~regional standards area

of the other Regional Entities ~~adjoining SERC (RFC, MRO, SPP, and FRCC),~~ individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives to seek input on the proposed SAR. ~~-~~ SERC Staff will perform this posting on the SERC website and coordinate or send correspondences described in this and other steps of the process. SERC Staff will assist in developing a response to any comments received. Any accompanying revision to the SAR based on comments received must be approved by the Executive Committee(s) of the assigned SERC Standing Committee(s).

Step 5: Formation of a Responsible SERC Subgroup

Within 60 days of accepting a SAR for development, the Executive Committee(s) of the assigned SERC Standing Committee(s) ~~Executive Committee(s)~~ shall assign and direct the proposal to the appropriate Responsible SERC Subgroup (RSS) to develop the draft Regional Reliability Standard. ~~-~~The RSS may be a permanent Standing Committee subgroup (augmented by other persons as may be appropriate to address the subject matter of the proposed standard), or a task force established expressly by the Executive Committee(s) for drafting the standard. SERC membership is not a prerequisite for serving on an RSS.

After consulting with the Executive Committee(s) of the assigned SERC Standing Committee(s) ~~Executive Committee(s)~~ as necessary, the SERC Standards Committee (SC) will assign a preliminary date on which the RSS is expected to have ready a completed draft Standard and associated supporting documentation available for consideration.

Step 6: Drafting of a SERC Regional Reliability Standard

The RSS shall develop a work plan for completing the regional reliability standard, including the establishment of a milestone schedule for completing critical elements of the work in sufficient detail to ensure that the RSS will meet the objectives established by the SC. ~~-~~The RSS shall submit its work plan to the SC for its concurrence. Any subsequent revision to the plan by the RSS which delays balloting the draft standard by 60 days or longer will be presented to the SC for its concurrence.

The RSS shall convene periodically, either in person or by electronic means as necessary, establish work teams (made up of members of the RSS) as necessary, and perform other activities to complete the proposed standard within the milestone date(s) agreed upon by the SC. ~~-~~All in-person RSS meetings or portions of meetings associated with development of the draft standard shall be open and publicly noticed on the SERC website for a minimum of twenty-one (21) calendar days prior to the meeting. ~~-~~ All conference call and electronic (WebEx) RSS meetings or portions of meetings

associated with development of the draft standard shall be open and publicly noticed on the SERC website for a minimum of seven (7) calendar days prior to the meeting. All RSS meeting attendees are required to register via the SERC website.

The RSS shall consider all comments received on the posting of the SAR and shall develop a draft SERC Regional Reliability Standard that will address the accepted SAR. The RSS shall use the ~~SERC Regional~~most current version of the approved NERC Reliability ~~Standards Format Template~~ Standard template and its associated elements posted on the NERC website as the format for the draft standard ~~(see Appendix D). The SERC Regional Reliability Standards Format Template can be downloaded from the SERC website (www.serc1.org).~~

~~The work product of the RSS~~
The work product of the RSS will be completed before taking the draft standard to ballot (Steps 9 and 10) and each item of the work product will be included as background information for at least one comments posting period (Step 7). The work product will consist of the following:

- A draft Standard consistent with the SAR on which it was based.
- An assessment of the reliability impact of the standard ~~on~~request within the region and in neighboring regions, ~~and~~including appropriate input from the neighboring regions if the standard request is ~~determined~~likely to impact any neighboring region. Communications between neighboring regions may be through the regional standard drafting teams, the regional standards development staff, or other means as appropriate.
- An implementation plan, including the nature, extent and duration of field-testing, if any.
- Identification of any existing Standard that will be deleted, in part or whole, or otherwise impacted by the implementation of the draft Standard
- Technical reports, white papers and/or work papers that provide technical support for the draft Standard under consideration.
- Documentation of the perceived reliability impact should the Standard be approved.

The RSS shall regularly inform the SC, at a frequency determined by the SC~~,~~ (RSS shall deliver a status report at every SC meeting at a minimum), of its progress in meeting a timely completion of the draft standard.~~-~~ The RSS may, with justification, request of the SC scope changes from the SAR at any point in the standard development process.

The RSS shall submit the draft SERC Regional Reliability Standard and supporting documentation to the SC for review**.** ~~-~~The RSS will send any revised SERC Regional Reliability Standard to the SC in both “Clean” and “Tracking” formats. ~~-~~The RSS shall also send the SC an accompanying Comments Form which may include specific

questions addressing the major issues associated with the new or revised standard. In any event, the Comments Form must also allow for general comments on the standard (see Appendix E for sample form). The SC will verify that the proposed standard is consistent with the SAR on which it was based. The SERC Regional Reliability Draft Standards Comments Form can be downloaded from the SERC website (www.serc1.org).

Step 7: Posting of a Draft SERC Regional Reliability Standard

The SERC Standards Committee shall send to the SERC Manager of Reliability Standards the draft SERC Regional Reliability Standard, along with a draft implementation plan and supporting documents, for comments. SERC Staff will post these documents on the SERC website for thirty (30) calendar days. A notice of the posting for comment will be sent to all SERC Standing Committees representatives and alternates. In addition, the request will be sent (via e-mail) to NERC, the ~~Region Managers~~regional standards area of the other Regional Entities ~~adjoining SERC (RFC, MRO, SPP, and FRCC),~~ individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives to seek input on the draft SERC Regional Reliability Standard. Comments shall be submitted electronically (via e-mail) to regstd@serc1.org. All comments are due by the close of business on the 30th calendar day of posting. If the comment due date falls on a weekend or nationally recognized holiday, the comments shall be due by the close of business on the next regularly scheduled business day.

Step 8: Standard Drafting Team Review of Comments

SERC Staff shall forward all comments received to the RSS ~~and SC. The SC may review comments and make recommendations concerning them. Any SC recommendation will be forwarded to the RSS.~~ . The RSS shall review the comments received and revise the draft SERC Regional Reliability Standard as needed. The RSS shall develop a written response to each comment received using the Consideration of Comments Form Template (see Appendix F). The SERC Consideration of Comments Form Template can be downloaded from the SERC website (www.serc1.org). The completed Consideration of Comments Form will be posted on the SERC website.

The RSS shall summarize comments that were rejected by the RSS and the reason(s) that these comments were rejected, in part or whole. The RSS shall submit to the SC the summary of comments rejected, the completed Consideration of Comments form, and any resulting revisions to the draft SERC Regional Reliability Standard.

If needed, a second draft of the SERC Regional Reliability Standard (along with the summary of comments rejected and the Consideration of Comments from the previous

posting) will be posted for another comment period. Such comment period shall be for thirty (30) calendar days. A notice of the posting for comment will be sent to all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to NERC, the ~~Region Managers~~regional standards area of the other Regional ~~Reliability Organizations adjoining SERC (RFC, MRO, SPP, and FRCC),~~Entities, individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives to seek input on the revised draft SERC Regional Reliability Standard.

Based on comments received to the posting, Step 7 will be repeated as necessary until the RSS and the SC ~~believe the draft SERC Regional Reliability Standard is ready to submit to the SERC Ballot Body for approval~~agree that no additional comments posting periods are warranted.

The SERC Manager of Reliability Standards will then request the NERC regional standards staff to make arrangements for a formal quality review of the draft standard. The RSS will develop responses to any recommendations from that review, including developing revisions to the draft standard if appropriate. The SDT and SC must agree on those responses prior to taking one of the two following actions:

- Submit the draft standard for an additional comment posting period (Step 7); or
- Submit the draft standard to the SERC Ballot Body for approval (Step 9).

The SC will determine if an additional NERC formal quality review will be requested for a draft standard which has been revised based on responses to an addition comments posting period.

Step 9: Notice of Vote to Approve a SERC Regional Reliability Standard

The Responsible SERC Subgroup shall submit the summary of comments rejected and the Consideration of Comments document along with the final draft of the proposed SERC Regional Reliability Standard (both “Tracking” and “Clean” versions for standard revisions) to the SERC Manager of Reliability Standards for posting on the SERC website at least 15 days prior to requesting approval of the standard.

The SERC Manager of Reliability Standards shall post the proposed standard and implementation plan for ballot and shall announce the vote to approve the standard, including when the vote will be conducted and the method for voting. Once the notice for a vote has been issued, no substantive modifications may be made to the proposed standard unless the revisions are posted and a new notice of the vote is issued.

Ballot Pool: The SERC Manager of Reliability Standards shall establish a ballot pool for a standard action at least 15 days prior to the start of a ballot. The SERC Manager of Reliability Standards shall send a notice to every entity in the Registered Ballot Body. The purpose of this notice is to establish a ballot pool to participate in the ballot of the proposed standards action.

Any member of the Registered Ballot Body may join or drop out of a ballot pool until the ballot period begins (Step 10). No Registered Ballot Body member may join or leave the ballot pool once the first ballot starts. The SERC Manager of Reliability Standards shall coordinate changes to the membership of the ballot pool and publicly post the standard ballot pool for each standard action.

The SERC Manager of Reliability Standards shall schedule a vote by the ballot pool for approval. ~~-~~The vote shall commence no sooner than 15 days and no later than 30 days following the issuance of the notice for the vote.

Step 10: SERC Ballot Pool of Registered Ballot Body Approval

The Ballot Pool shall have a minimum of ten (10) days to vote on a standards action. The Ballot Pool should give due consideration to the work of the RSS, as well as the comments of stakeholders and minority objections, in approving a proposed regional reliability standard. ~~-~~The Ballot Pool may vote to approve or not approve the standard. The ballot will include provisions for comments. The RSS shall develop a written response to each ballot comment received.

~~Once approved, the SERC Regional Reliability Standard along with the proposed implementation plan and supporting documentation will be submitted by the SERC President, or the President's designee, to the SERC Board of Directors for adoption.~~

If approval by the RBB is not obtained, the Standing Committee(s) will determine if the draft SERC Regional Reliability Standard is to be sent back to the RSS to repeat Step 8 to incorporate any RBB or SERC Standing Committee(s) comments, form a new RSS for that purpose, or to ~~take no further action on~~ withdraw the proposed SERC Regional Reliability Standard.

If ~~no further action is taken~~ the standard is withdrawn, the reason for such will be posted on the SERC website. ~~-~~A notice of the posting will be sent to all SERC Standing Committee representatives and alternates. ~~-~~In addition, the notice will be sent (via e-mail) to NERC, the ~~Region Managers~~regional standards area of the other Regional Entities ~~adjoining SERC (RFC, MRO, SPP, and FRCC),~~ individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives.

Step 11: ~~Adoption~~Submission of SERC Regional Reliability Standards to NERC to post for comments

Once the SERC Regional Reliability Standard is approved by the SERC RBB, the SERC Manager of Reliability Standards will forward it to NERC and request that they post it for comments in accordance with the NERC Regional Reliability Standards Evaluation Procedure.

The Responsible SERC Subgroup will develop a response to any comments received and submit it along with any associated standard modifications to the SERC Standards Committee for approval. The SERC Standards Committee may approve minor editorial type modifications that do not have a substantive impact. If the Responsible SERC Subgroup proposes any substantive modifications, the SERC Standards Committee may 1) remand it back to the Responsible SERC Subgroup for further consideration; or 2) accept the proposed modification and send it back to Step 9 to re-ballot the standard.

Step 12: Approval of SERC Regional Reliability Standards by the SERC Board of Directors

The SERC Board of Directors shall consider ~~adoption~~approval of any SERC Regional Reliability Standard that has been approved by the SERC RBB~~.~~ and has received SERC Standards Committee approval of the resolution of comments received during the Step 11 posting. A SERC Regional Reliability Standard submitted for ~~adoption~~approval by the SERC Board of Directors must be posted for notification on the SERC website at least 15 days prior to action by the SERC Board of Directors. A notice of the posting will be sent to all SERC Board of Directors representatives and alternates, and to all SERC Standing Committee representatives and alternates. In addition, the notice will be sent (via e-mail) to NERC, the ~~Region Managers~~regional standards area of the other Regional Entities ~~adjoining SERC (RFC, MRO, SPP, and FRCC)~~ and to any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System.

The SERC Board of Directors shall consider the comments received, the responses provided, and any dissenting opinions. The SERC Board of Directors shall ~~adopt~~approve or reject a SERC Regional Reliability Standard as submitted, but may not substantively modify the proposed SERC Regional Reliability Standard.

If the SERC Board of Directors chooses to reject a SERC Regional Reliability Standard as submitted, it shall provide its reasons for doing so. The reasons for such decision will be posted on the SERC website. A notice of the posting will be sent to all SERC Standing Committees representatives and alternates. In addition, the notice will be sent

(via e-mail) to NERC, the ~~Region Managers~~regional standards area of the other Regional Entities ~~adjoining SERC (RFC, MRO, SPP, and FRCC),~~ individuals listed as entity contacts in the SERC Compliance Registry, and the SERC Registered Ballot Body representatives. ~~-~~ The assigned Standing Committee(s) will determine if the draft standard should be resubmitted with modifications. ~~-~~If so, the draft standard will be remanded back to the RSS in Step 8 above.

Step ~~12~~13: Submission of SERC Regional Reliability Standards to NERC and FERC

Once the SERC Regional Reliability Standard is ~~adopted~~approved by the SERC Board of Directors, the SERC President, or the President's designee shall submit the SERC Regional Reliability Standard to NERC for ~~approval~~adoption and filing with FERC. ~~NERC will post the~~ The SERC ~~Regional~~Manager of Reliability ~~Standard for comments. The Responsible SERC Subgroup will develop a response to any comments and submit it to the~~ Standards ~~Committee for approval. When the Responsible SERC Subgroup response is approved by the Standards Committee, the SERC President, or the President's designee will forward the comments to NERC~~will ensure the record of the standard development and any other documentation required for consideration by the NERC Board~~.~~ or FERC are included in the submittal.

If the NERC Board rejects the SERC Regional Reliability Standard the SERC Board will determine if the SERC Regional Reliability Standard is to be sent back to the assigned SERC Standing Committee(s) to incorporate the NERC Board comments or to ~~take no further action on~~withdraw the standard.

When ~~approved~~adopted by the NERC Board, NERC will submit the SERC Regional Reliability Standard to FERC for approval. ~~-~~ If FERC rejects the SERC Regional Reliability Standard, the SERC Board will determine if the SERC Regional Reliability Standard is to be sent back to the assigned SERC Standing Committee(s) to incorporate the FERC comments or to ~~take no further action on~~withdraw the standard.

Step ~~13~~14: Implementation of SERC Regional Reliability Standards

A SERC Regional Reliability Standard that is ~~adopted~~approved by the SERC Board of Directors, NERC, and FERC, shall become effective on a date designated by FERC. ~~-~~ In developing the standard, the RSS should consider the time needed for NERC and FERC approval in the proposed implementation date.

Appendix A: Stakeholder Representation

A.1 SERC Standing Committees and Member Representation

Membership in SERC is open to any entity in the SERC Region that is a user, owner or operator of the Bulk ~~Power~~ Electric System and subject to the jurisdiction of the Federal Energy Regulatory Commission for the purpose of complying with Reliability Standards established under Section 215 of the Federal Power Act and all amendments thereto. SERC~~'s membership policy~~ permits full and fair participation of all Member Companies~~members~~ through their representatives, including in the development of and voting on Regional Reliability Standards. ~~-~~The SERC standing committees have a role in developing standards, a ballot pool of the SERC Registered Ballot Body vote to approve Regional Reliability Standards, and the SERC Board of Directors adopts all standards. Since each ~~member~~ Member Company is entitled to representation on both the Board and the Standing Committees, SERC's membership policy permits full and fair participation of its ~~members~~ Member Companies.

The Standing Committees and their voting rights shall be established pursuant to the SERC Bylaws. ~~The following are excerpts from the SERC Reliability Corporation Bylaws. Section 8.1 establishes the Standing Committees and SERC Member representation on those committees. Section 8.2 specifies committee voting rights will be based on the same method as adopted by the SERC Board of Directors, and refers~~Refer to the committee scope documents and the Organization and Procedures Manual for SERC Standing Committees for more specific details.

> ~~*8.1 Designation by Board. The Board of Directors, by resolution adopted by a Bicameral Simple Majority, may designate standing and special (ad hoc) committees, as shall be necessary to address the purposes of the Corporation. Such committees shall include, but are not limited to the following:*~~
>
> ~~*(a) Engineering Committee -- The purpose of this committee shall be to promote the reliability and adequacy of the Bulk-Power System, as related to the planning and engineering of electric systems. The committee shall provide a mechanism for the coordination of activities in the areas of planning and engineering.*~~
>
> ~~*b) Operating Committee -- The purpose of this committee shall be to promote the reliability and adequacy of the Bulk-Power System, as related to the operation of electric systems. The committee shall provide a mechanism for the coordination of activities in the area of operations.*~~
>
> ~~*(c) Critical Infrastructure Protection Committee -- The purpose of this committee shall be to promote the advancement of the physical and cyber security of the Bulk-Power System. It serves as an expert advisory panel in the areas of*~~

~~*physical and cyber security, establishes and maintains an information reporting procedure, provides a liaison with state government agencies, and conducts forums and workshops related to Critical Infrastructure Protection.*~~

~~*Each Member is entitled, but not required, to name both a representative and alternate to the committees designated in this Section 8.1.*~~

~~*8.2 Voting Rights for Committees. Except as otherwise provided for in these Bylaws, voting rights for the Committees established pursuant to Section 8.1 shall be based on the same method as adopted by the Board of Directors of the Corporation. Operating procedures, definitions for quorum, and votes for approval are contained in the Organization and Procedures Manual for the Corporation's Standing Committees.*~~

A.2 SERC Regional Reliability Standards Voting Procedures

The following are the voting procedures for the SERC Registered Ballot Body:

1. Registration Procedures

The Registered Ballot Body (RBB) comprises all organizations and entities that:

- Qualify for one of the SERC Sectors, and
- Are registered with SERC as potential ballot participants in the voting on standards.

All registrations will be done electronically. Each participant, when initially registering to join the RBB will self-select to belong to one of the Sectors and will also name their RBB representative. The Executive Committee of the Board of Directors or its designee will review all applications for joining the Registered Ballot Body, and make a determination of whether the self-selection satisfies the criteria to belong to that sector. ~~The Sectors shall be identical to those in Section 3.4 of the SERC's Bylaws.~~

All registered organizations and entities that qualify for a Sector with SERC may vote on a standard. ~~-~~Voting is in writing with each registered stakeholder (a "stakeholder") having one vote. The stakeholder's RBB representative will have the right to register to participate in ballot pools and cast the stakeholder's vote.

2. Sector Qualification Guidelines

The sector qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the SERC ~~bulk power system~~Bulk Electric System that

can meet the criteria for a sector as defined in ~~Section 3.4 of~~ the SERC's Bylaws is entitled to belong to and vote in that sector. The general guidelines are:

- Corporations or organizations with affiliates that qualify to belong to more than one sector (e.g., Investor-Owned Utility and Merchant Electricity Generator) may belong to each of the sectors in which they qualify, provided that each sector ~~constitutes a separate membership and~~ is represented by a different representative.
- At any given time, affiliated entities may collectively be registered only once within a sector.
- Any individual currently employed by an organization that is eligible to join one of the other seven sectors, shall not be qualified to join as a "customer" in the ISO-RTO/Customer sector.

3. Definitions

Individual Vote – shall mean a single vote accorded to each stakeholder.

4. Quorum

Two-thirds of the Individual Votes of the Ballot Pool shall constitute a quorum.

5. SERC Registered Ballot Body Voting Requirements

A ballot pool will be established to participate in the ballot of any proposed standards action. Approval of a reliability standard or revision to a reliability standard requires the affirmative vote of a two thirds majority of the weighted Sector votes cast. The number of votes cast in each Sector is the sum of affirmative and negative votes, excluding abstentions and non-response.

The following process is used to determine if there are sufficient affirmative votes.

- The number of affirmative votes cast in each Sector will be divided by the sum of affirmative and negative votes cast to determine the fractional affirmative vote for each Sector. Abstentions and non-responses will not be counted for the purposes of determining the fractional affirmative vote for a Sector.
- The fractional affirmative vote for a Sector is then multiplied by the Sector weight factor, to determine the weighted fractional affirmative vote for a Sector. The weight factors for the Sectors are:
  - Investor-Owned Utility Sector: weight factor is 3.
  - Federal/State Sector: weight factor is 2.

  - Cooperative Sector: weight factor is 2.
  - Municipal Sector: weight factor is 2.
  - Marketer Sector: weight factor is 1.
  - Merchant Electricity Generator Sector: weight factor is 1.
  - ISO-RTO/Customer Sector: weight factor is 1.
- The sum of the weighted fractional affirmative votes from all Sectors divided by the sum of the weights of the Sectors voting will be used to determine if a two-thirds majority has been achieved. (A Sector will be considered as "voting" if any member of the Sector in the ballot pool casts either an affirmative or a negative vote.)
- A standard will be approved if the sum of weighted fractional affirmative votes from all Sectors divided by the sum of the weights of the voting Sectors is two-thirds or greater.

Appendix B: Principles, Characteristics, and Special Procedures

Principles

SERC develops regional standards with due consideration of the following principles, in accordance with the steps outlined in this procedure. This procedure has been designed to ensure that any SERC Regional Reliability Standard is technically sound and the technical specifications proposed will achieve a valuable reliability objective.

The SERC Regional Reliability Standards Development Procedure has the following characteristics:

- **Open:** Participation in the development of a SERC Regional Reliability Standard shall be open to all organizations that are directly and materially affected by the SERC ~~bulk power system~~Bulk Electric System reliability. There shall be no undue financial barriers to participation. Participation shall not be conditioned upon membership in SERC, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements. Meetings of the Responsible SERC Subgroup assigned to draft a standard shall be open to the SERC ~~member~~Member Companys and others.

- **Balanced:** The SERC Regional Reliability Standards Development Procedure strives to have an appropriate balance of interests and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter.

- **Inclusive:** Any entity (person, organization, company, government agency, individual, etc.) with a direct and material interest in the ~~bulk power system~~Bulk Electric System in the SERC ~~area~~ Region shall have a right to participate by: a) expressing a position and its basis, b) having that position considered, c) registering as a potential ballot participant and voting on a proposed standard; and d) having the right to appeal**.**

- **Fair due process:** The SERC Regional Reliability Standards Development Procedure provides for reasonable notice and opportunity for public comment. This procedure includes public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.

- **Transparent:** All actions material to the development of SERC Regional Reliability Standards shall be transparent. All standards development meetings shall be open

and publicly noticed on the SERC Web site.

- **Due Course:** Does not unnecessarily delay development of the proposed SERC Regional Reliability Standard.

NERC has adopted reliability principles and market interface principles to define the purpose, scope, and nature of reliability standards. These principles are to be used to guide the development of reliability standards, including regional reliability standards. The NERC Board of Trustees may modify these principles from time to time, as necessary, to adapt its vision for reliability standards.

- Each SERC Regional Reliability Standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional ~~bulk power system.~~ Bulk Electric System. Each standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

- While reliability standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. Reliability is a necessity for electricity markets, and robust electricity markets can support reliability. Recognizing that ~~bulk power system~~Bulk Electric System reliability and electricity markets are inseparable and mutually interdependent, all SERC Regional Reliability Standards shall be consistent with NERC's market interface principles. Consideration of the market interface principles is intended to ensure that standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

Regional Reliability Standard Characteristics and Elements

Characteristics of a SERC Regional Reliability Standard

The following characteristics describe objectives to be considered in the development of SERC Regional Reliability Standards:

1. **Applicability**: Each SERC Regional Reliability Standard clearly identifies the functional classes of entities responsible for complying with the standard, with any specific additions or exceptions noted. Such functional classes include: reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange ~~authorities~~coordinators, transmission service providers, ~~market operators,~~ planning ~~authorities~~coordinators,

transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each SERC Regional Reliability Standard identifies the geographic applicability of the standard. A standard may also identify any limitations on the applicability of the standard based on electric facility characteristics.

2. **Reliability Objectives**: Each SERC Regional Reliability Standard has a clear statement of purpose that describes how the standard contributes to the reliability of the ~~bulk power system~~Bulk Electric System.

3. **Requirement or Outcome**: Each SERC Regional Reliability Standard states one or more requirements, which if achieved by the applicable entities, will provide for a reliable ~~bulk power system~~Bulk Electric System, consistent with good utility practices and the public interest.

4. **Measurability**: Each performance requirement is stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Each performance requirement has one or more associated measures used to objectively evaluate compliance with the requirement. If performance can be practically measured quantitatively, metrics are provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations**: Each regional reliability standard is based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness**: Each SERC Regional Reliability Standard is complete and self-contained. Supporting references may be provided with standards, but they are not part of the standard and do not impose mandatory requirements.

7. **Clear Language**: Each SERC Regional Reliability Standard is stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practice, are able to arrive at a consistent understanding of the required performance.

8. **Practicality**: Each SERC Regional Reliability Standard establishes requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

9. **Consistent Terminology:** To the extent possible, SERC Regional Reliability Standards use a set of standard terms and definitions that are approved through the SERC Regional Reliability Standard Development Procedure.

Although regional reliability standards have a common format and process, several types of standards may exist, each with a different approach to measurement:

- Technical standards are related to the provision, maintenance, operation, or state of electric systems, and will likely contain measures of physical parameters that are technical in nature.

- Performance standards are related to the actions of entities providing for or impacting the reliability of the ~~bulk power system~~Bulk Electric System, and will likely contain measures of the results of such actions or qualities of performance of such actions.

- Preparedness standards are related to the actions of entities to be prepared for conditions that are unlikely to occur, but are nonetheless critical to reliability, and will likely contain measures of such preparations or the state of preparedness.

Elements of a SERC Regional Reliability Standard

To ensure uniformity of SERC Regional Reliability Standards, a SERC Regional Reliability Standard shall consist of the elements identified in Appendix D of this procedure. ~~-~~However, the most current version of the approved NERC Reliability Standard template and its associated elements posted on the NERC website will be used at the time of the development of the SERC Regional Reliability Standard if different from the elements listed in Appendix D. This is to ensure all essential elements are contained in the SERC standard to achieve consistency and uniformity and meet all statutory requirements. These elements are intended to apply a systematic discipline in the development and revision of standards. ~~-~~This discipline is necessary to achieving standards that are measurable, enforceable, and consistent.

All mandatory requirements of a SERC Regional Reliability Standard shall be within the standard. ~~-~~Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself.

Maintenance of the SERC Regional Reliability Standards Development Procedure

Any ~~member~~ Member Company of SERC, or group (or member of a group) within SERC (i.e., committee, subcommittee, working group, study group, task force, or SERC staff), or any entity that is directly and materially affected by the reliability of the SERC Bulk ~~Power~~Electric System may submit a written request to modify the SERC Regional

Reliability Standard Development Procedure. The Manager of Reliability Standards shall oversee the handling of the request.

Significant changes to this procedure shall be addressed using the same procedure as a request to develop, modify, or withdraw a SERC Regional Reliability Standard. For any such changes to this procedure, the SERC Standards Committee will assume the responsibilities normally assigned to the Executive Committee(s) of the SERC Standing Committee(s) in Steps 3, 5, and 10.

For any minor changes to this procedure, the SERC Standards Committee shall review the request and submit recommendations to the SERC Board of Directors for consideration. The SERC Board of Directors, on its own motion, may amend the SERC Regional Reliability Standard Procedure.

Maintenance of SERC Regional Reliability Standards

Each SERC Regional Reliability Standard shall be reviewed at least once every five (5) years. The review date will be determined from the effective date or the latest revision date, whichever is later. The review process shall be conducted in accordance with Steps 1 through ~~13~~14 of the SERC Regional Reliability Standard Development Procedure. As a result of this review, a SERC Regional Reliability Standard shall be reaffirmed, revised, or withdrawn.

Interpretations of Standards

Any ~~member~~ Member Company of SERC, or group within SERC, or an entity that is directly and materially affected by reliability of the SERC Bulk Electric System shall be permitted to request an interpretation of a SERC Regional Reliability Standard ~~or regional criteria documented in a SERC Standing Committee Document. Any such entity shall also be permitted to request implementation guidance regarding how the SERC compliance program will be measuring and enforcing a NERC Reliability Standard[1].~~. The entity requesting an interpretation ~~or implementation guidance~~ shall send a request to regstd@serc1.org explaining the specific circumstances surrounding the request and what clarifications are required as applied to those circumstances. The request should indicate the material impact to the requesting party, or others, caused by the lack of clarity or a possible incorrect interpretation. SERC Staff will forward requests for interpretations to the ~~appropriate~~ SERC ~~Standing~~Standards Committee ~~Chair(s),~~ who will assign ~~a Responsible SERC Subgroup~~an Interpretation Drafting Team (IDT) with the relevant expertise to address the clarification. The IDT should include

[1] ~~This is different than requesting an interpretation of the meaning of a NERC Reliability Standard itself, which must be addressed through the NERC process by submitting a request for interpretation to NERC.~~

appropriate industry stakeholder representatives and members of the original Standard Drafting Team, consistent with availability.

As soon as practical [but not more than forty-five (45) calendar days following ~~the receipt~~establishment of the ~~request~~IDT], the ~~assigned subgroup~~IDT will prepare a draft ~~a written~~ interpretation of the SERC Regional Reliability Standard ~~or regional criteria~~ addressing the issues raised. ~~The~~ SERC Staff will post the draft interpretation ~~will be~~ on the SERC website for 30-day informal[2] stakeholder comment period. A notice of the posting will be sent to all SERC Standing Committees representatives and alternates; NERC; the regional standards area of the other Regional Entities; individuals listed as entity contacts in the SERC Compliance Registry; and the SERC Registered Ballot Body representatives by email. Comments shall be submitted ~~to the appropriate SERC Standing~~ electronically by email to regstd@serc1.org. All comments are due by the close of business on the 30th calendar day of posting. If the comment due date falls on a weekend or nationally recognized holiday, the comments shall be due by the close of business on the next regularly scheduled business day.

The IDT will review the stakeholder feedback and may revise the draft interpretation. The IDT will then forward the draft interpretation to the SERC Standards Committee~~(s) Executive~~ for review. The Standards Committee ~~for review~~will determine if the interpretation is consistent with the standard and does not add additional requirements to the standard. The interpretation will then be posted for public review and a ballot pool will be formed consistent with the process steps to approve a draft standard as detailed in the body of this procedure. The interpretation is then balloted and, if approved, will be submitted for SERC Board of Directors approval and filing with NERC and FERC.

~~As soon as practical [but not more than twenty (20) calendar days following the receipt of the written interpretation from the RSS], the SERC Standing Committee Executive Committee will develop a written recommendation to the SERC Executive Committee concerning approval of the interpretation. The SERC Standing Committee Executive Committee must recommend either that 1) the RSS written interpretation; or 2) a revision of that interpretation be approved. The recommendation, the RSS written interpretation, and any revised interpretation will be forwarded to the SERC Executive Committee.~~

If approved by ~~the SERC Executive Committee~~FERC, the interpretation is appended to the SERC Regional Reliability Standard ~~or SERC regional criteria~~ and is effective immediately. ~~-~~The interpretation will stand until such time as the SERC Regional Reliability Standard ~~or SERC Standing Committee Document~~ is revised through the normal process, at which time the SERC Regional Reliability Standard ~~or SERC~~

[2] An informal comment period does not require the IDT to respond to every stakeholder comment and is only used to make potential changes for the final draft of the interpretation.

~~Standing Committee Document~~ will be modified to incorporate the clarifications provided by the interpretation.

~~Requests for implementation guidance regarding how the SERC compliance program will be measuring and enforcing a NERC Reliability Standard will be forwarded to the SERC Compliance staff. The SERC Compliance staff will assign the request to the applicable compliance advisory group to develop appropriate implementation guidance. As soon as practical [but not more than forty-five (45) calendar days following the receipt of the request], the assigned compliance advisory group will draft written implementation guidance for review by the SERC Compliance staff. The SERC Compliance staff will notify the requestor of the approved implementation guidance.~~

Appeals

Any ~~member~~ Member Company of SERC or any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System that believes it has been or will be adversely affected by any substantive or procedural action or inaction related to the development, approval, revision, or withdrawal of a SERC Regional Reliability Standard shall have the right to appeal. ~~-~~This appeals process applies only to the SERC Regional Reliability Standards Process as defined in this manual. ~~-~~The burden of proof to show adverse effect shall be on the appellant.~~-~~ Appeals shall be made within thirty (30) calendar days of the date of the action purported to cause the adverse effect. ~~-~~The final decisions of any appeal shall be documented in writing and posted on the SERC Member Company website. ~~-~~A notice of the posting will be sent to all SERC Board of Directors representatives and alternates, and to all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to the ~~Region Managers~~regional standards area of the other Regional Entities ~~adjoining SERC (RFC, MRO, SPP, and FRCC)~~ and to any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants:

Level 1 Appeal

Level 1 is the required first step in this appeals process. ~~-~~The appellant submits to the SERC President a complaint in writing that describes the substantive or procedural action associated with a SERC Regional Reliability Standard or the SERC Regional Reliability Standards Process. ~~-~~The appellant must describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary staff and the SERC Standards Committee, the SERC President, or the President's designee shall prepare a written response addressed to

the appellant as soon as practical but not more than forty-five (45) calendar days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response will be made a part of the record associated with the SERC Regional Reliability Standard.

Level 2 Appeal

If after the Level 1 Appeal, the appellant remains unsatisfied with the resolution, notification shall be made in writing to the SERC President within fifteen (15) calendar days of the affected entity's Level 2 Appeal to the SERC Executive Committee. In all cases, no SERC Executive Committee members that have any direct affiliation with the participants in the appeal will participate in the Level 2 Appeal.

SERC Staff shall post on the SERC website the notice of the Level 2 appeal and other relevant materials at least fifteen (15) calendar days prior to consideration of the Level 2 appeal by the SERC Executive Committee.

In addition to the appellant, any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System, and who is directly and materially affected by the substantive or procedural action referenced in the complaint shall be heard by the SERC Executive Committee. The SERC Executive Committee shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal.

The Executive Committee may direct the SERC Standards Committee to research and/or advise it on technical issues or matters related to the appeal. Each appellant, any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System, and who is directly and materially affected by the substantive or procedural action referenced in the complaint may request that an ad-hoc committee be formed to assist the Executive Committee in its review.

The SERC Executive Committee may in its decision find for the appellant and remand the issue to the SERC Standards Committee for resolution with a statement of the issues and facts in regard to which fair and equitable action was not taken.

The SERC Executive Committee may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections.

The actions of the SERC Executive Committee shall be posted on the SERC website. A notice of the posting will be sent to the appellant, all SERC Board of Directors representatives and alternates, and all SERC Standing Committees representatives and alternates. In addition, the notice will be sent (via e-mail) to the ~~Region Managers~~regional standards area of the other Regional Entities ~~adjoining SERC (RFC,~~

~~MRO, SPP, and FRCC)~~ and to any entity that is directly and materially affected by the reliability of the SERC Bulk Electric System.

Appendix C: SERC Regional Reliability Standard Authorization Request Form (Latest approved version of form is posted on the SERC website: www.serc1.org)

SERC to complete
ID
Authorized for Posting
Authorized for Development

Title of Proposed Standard:
Request Date:

SAR Originator Information

Name	**SAR Type** (Check box for one of these selections.)	
Company		New Standard
Telephone		Revision to Existing Standard
Fax		Withdrawal of Existing Standard
E-mail	---	----------

Purpose (Describe the purpose of the proposed Standard — what the Standard will achieve in support of reliability.)

For Example Only

Industry Need (Provide a detailed statement justifying the need for the proposed Standard, along with any supporting documentation.)

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

Justification ~~for Regional Variation~~ (Provide a detailed statement justifying the need for the proposed ~~Standard specifically identifying the need for a regional variation~~standard.)

Reliability Functions

The Standard ~~will~~May Apply to the Following Functions (Check box for each one that applies.)		
	Reliability ~~Authority~~Coordinator	~~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 Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.~~ Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
	Balancing Authority	~~The responsible entity that integrates~~Integrates resource plans ahead of time, and maintains load-interchange-~~generation~~resource balance within a

For Example Only

		Balancing Authority Area~~,~~ and supports Interconnection frequency in real time.
	Interchange ~~Authority~~Coordinator	~~Authorizes valid and balanced Interchange Schedules~~ Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
	Planning ~~Authority~~Coordinator	~~The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.~~Assesses the longer-term reliability of its Planning Coordinator Area.
	Transmission Service Provider	~~The entity that administers~~Administers the transmission tariff and provides ~~Transmission Service to Transmission Customers~~transmission services under applicable transmission service agreements~~.~~ (e.g., the pro forma tariff).
	Transmission Owner	~~The entity that owns~~Owns and maintains transmission facilities.
	Transmission Operator	~~The entity responsible for~~ Ensures the Real-time operating reliability of ~~its "local"~~the transmission ~~system, and that operates or directs the operations of the transmission facilities~~assets within a Transmission Operator Area.
	Transmission Planner	~~The entity that develops~~Develops a ~~long-term (generally~~ >one year ~~and beyond)~~ plan for the reliability ~~(adequacy)~~ of the interconnected ~~bulk electric transmission systems~~Bulk Electric System within its portion of the Planning ~~Authority Area~~Coordinator area.
	Resource Planner	~~The entity that develops~~Develops a ~~long-term (generally~~ >one year ~~and beyond)~~ plan for the resource adequacy of its specific loads ~~(customer demand and energy requirements)~~ within a Planning ~~Authority Area~~Coordinator area.
	Generator Operator	~~The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.~~Operates generation unit(s) to provide real and reactive power.
	Generator Owner	~~Entity that owns~~Owns and maintains ~~generating units~~generation facilities.

For Example Only

	Purchasing-Selling Entity	~~The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.~~Purchases or sells energy, capacity, and necessary reliability-related services as required.
	Distribution Provider	~~Provides and operates~~Delivers electrical energy to the ~~"wires" between the transmission system and the~~End-use customer.
	Load-Serving Entity	Secures energy and transmission service (and reliability-related ~~Interconnected Operations Services~~services) to serve the ~~electrical demand and energy requirements of its end~~End-use ~~customers.~~ Customer.

NOTE: The RSS may find it necessary to modify the initial reliability function responsibility assignment as a result of the standards development and comments received.

Applicable Reliability Principles *(Check all boxes that apply.)*	
☐	1. Interconnected ~~bulk power systems~~Bulk Electric Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected ~~bulk power systems~~Bulk Electric Systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected ~~bulk power systems~~Bulk Electric Systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected ~~bulk power systems~~Bulk Electric Systems shall be developed, coordinated, maintained, and implemented.
☐	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected ~~bulk power systems.~~Bulk Electric Systems.
☐	6. Personnel responsible for planning and operating interconnected ~~bulk power systems~~Bulk Electric Systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected ~~bulk power systems~~Bulk Electric Systems shall be assessed, monitored, and maintained on a wide-area basis.

For Example Only

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an Common Attribute of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description *(*Provide enough detail so that an independent entity familiar with the industry could draft a Standard based on this description.*)*

Related Reliability Standards (NERC and SERC Regional)

Standard No.	Explanation

Related SARs

SAR ID	Explanation

For Example Only

Implementation Plan

Description *(Provide plans for the implementation of the proposed standard, including any known systems or training requirements. Include the reliability risk(s) associated with the violation that the standard will mitigate, and the costs associated with implementation.)*
Proposed Implementation ~~__~~days after Board of Directors ~~adoption~~approval or on (date):

For Example Only

Appendix D: Elements of a SERC Regional Reliability Standard

Title	A brief, descriptive phrase identifying the topic of the standard.
Identification Number	A unique identification number assigned to facilitate tracking and reference to SERC Regional Reliability Standards. The identification number will be consistent with the Numbering Convention for NERC Regional Reliability Standards. The latest approved version of the convention will be posted on the SERC website (www.serc1.org).
Effective Date and Status	The effective date of the standard or, prior to ~~adoption~~approval of the standard by the Board of Directors, the proposed effective date.
Purpose	The purpose of the standard. ~~-~~The purpose shall explicitly state what outcome is expected by this standard.
Applicability	Clear identification of the functional classes of entities responsible for complying with the standard, noting any specific additions or exceptions. If not applicable to the entire SERC ~~area~~Region, then a clear identification of the portion of the ~~bulk power system~~Bulk Electric System to which the standard applies.~~-~~ Any limitation on the applicability of the standard based on electric facility requirements should be described.
Requirement(s)	Explicitly stated technical, performance, and preparedness requirements.~~-~~ Each requirement identifies what entity is responsible and what action is to be performed or what outcome is to be achieved. ~~-~~Each statement in the requirements section shall be a statement for which compliance is mandatory.

Violation Severity Levels	Defines the degree to which compliance with a requirement was not achieved. ~~The violation severity levels, are part of the standard and are balloted with the standard, and developed by the NERC and SERC compliance programs in coordination with the Responsible SERC Subgroup~~ Each requirement must have at least one Violation Severity Level.

Violation Risk Factor(s)	The potential reliability significance of each requirement, designated as a High, Medium, or Lower Risk Factor in accordance with the criteria listed below: A High Risk Factor requirement (a) is one that, if violated, could directly cause or contribute to ~~bulk power system~~Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the ~~bulk power system~~Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or (b) is a requirement in a planning timeframe that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to ~~bulk power system~~Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the ~~bulk power system~~Bulk Electric System at an unacceptable~~-~~ risk of instability, separation, or cascading failures, or could hinder restoration to abnormal condition. A Medium Risk Factor requirement (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the ~~bulk power system~~Bulk Electric System, or the ability to effectively monitor and control the ~~bulk power system~~Bulk Electric System, but is unlikely to lead to ~~bulk power system~~Bulk Electric System instability, separation, or cascading failures; or (b) is a requirement in a planning timeframe that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the ~~bulk power system~~Bulk Electric System, or the ability to effectively monitor, control, or restore the ~~bulk power system~~Bulk Electric System, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to ~~bulk power system~~Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition. A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the ~~bulk power system~~Bulk Electric System, or the ability to effectively monitor and control the ~~bulk power system~~Bulk Electric System; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the ~~bulk power system~~Bulk Electric System, or the ability to effectively monitor, control, or restore the ~~bulk power system~~Bulk Electric System.

Measure(s)	Each requirement shall be addressed by one or more measurements. Measurements that will be used to assess performance and outcomes for the purpose of determining compliance with the requirements stated above. Each measurement identifies to whom the measurement applies and the expected level of performance or outcomes required demonstrating compliance. Each measurement shall be tangible, practical, and as objective as is practical. It is important to realize that measures are proxies to assess required performance or outcomes. Achieving the full compliance level of each measurement should be a necessary and sufficient indicator that the requirement was met. Each measure shall clearly refer to the requirement(s) to which it applies.
Compliance Monitoring Process	Defines for each measure: • The specific data or information that is required to measure performance or outcomes. • The entity that is responsible for providing the data or information for measuring performance or outcomes. • The process that will be used to evaluate data or information for the purpose of assessing performance or outcomes. • The entity that is responsible for evaluating data or information to assess performance or outcomes. ~~• The time period in which performance or outcomes is measured, evaluated, and then reset.~~ • Measurement data retention requirements and assignment of responsibility for data archiving. ~~• Violation severity levels.~~

Time Horizon	The time period an entity has to mitigate an instance of violating the associated requirement. • Long-term Planning — a planning horizon of one year or longer. • Operations Planning — operating and resource plans from day-ahead up to and including seasonal. • Same-day Operations — routine actions required within the timeframe of a day, but not real-time. • Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system. • Operations Assessment — follow-up evaluations and reporting of real time operations.

Attached Supporting Information Elements

Interpretations	Any interpretations of the SERC Regional Reliability Standards that were developed, and approved by the SERC Executive Committee, to expound on the application of the standard for unusual or unique situations.
Implementation Plan	Each SERC Regional Reliability Standard shall have an associated implementation plan describing the effective date of the standard or effective dates if there is a phased implementation. The implementation plan may also describe the implementation of the standard in the compliance program and other considerations in the initial use of the standard, such as necessary tools, training, etc. The implementation plan must be posted for at least one public comment period and is approved as part of the ballot of the standard.
Supporting References	This section references related documents that support reasons for, or otherwise provide additional information related to the standard Examples include, but are not limited to: • Glossary of Terms • Developmental history of the standard and prior versions • Responsible SERC Subgroup • Notes pertaining to implementation or compliance • Standard references • Procedures/Practices • Training and/or Technical Reference • Frequently Asked Questions Document

Appendix E: Comment Form for Draft SERC Regional Reliability Standard (Latest approved version of form is posted on the SERC website: www.serc1.org)

COMMENT FORM FOR [INSERT APPROPRIATE TITLE OF SERC REGIONAL RELIABILITY STANDARD]

Please use this form to submit comments on **[insert description]**. Comments must be submitted by **[date].** You must submit the completed form by emailing it to **[insert appropriate contact names & e-mail addresses]** with the words **[insert appropriate subject]** in the subject line. If you have questions please contact **[insert appropriate contact names, e-mail addresses & phone numbers]**.

DO: **Do** use punctuation and capitalization as needed.
Do use more than one form if responses do not fit in the spaces provided.
Do submit any formatted text or markups in a separate WORD file.

DO NOT: **Do not** submit a response in an unprotected copy of this form.

Commenter Information
Group Name (if applicable):
Contact Name:
Organization:
Telephone:
Email:

Background:

In this section, provide background information including the reasons for the development of new SERC Regional Reliability Standard or revisions to an existing SERC Regional Reliability Standard.

Major Changes to this Revision of the SERC Regional Reliability Standard

Provide additional information that may help the reviewers better understand the need and motivation for the changes.

Include any other sections as necessary to facilitate the review process.

For Example Only

Please Enter All Comments in Simple Text Format.

Insert a "check' mark in the appropriate boxes by double-clicking the gray areas.

[The following are sample questions.- Revise the questions as appropriate.]

1. Do you agree with the inclusion of the following in section [xxx] of the standard?

   Describe revision details.

   ☐ Yes

   ☐ No

   ☐ Comments:

2. Do you agree with the proposed definitions that were added or revised?

   ☐ Yes

   ☐ No

   ☐ Comments:

3. Do you agree with the deletion of the following section from part [xxx]?

   ☐ Yes

   ☐ No

   ☐ Comments:

4. Do you agree with the proposed changes in section [xxx] of the document?

   ☐ Yes

   ☐ No

   ☐ Comments:

5. Please identify anything you believe needs to be modified before this revision of the standard can be approved by SERC?

   ☐ Comments:

6. Please provide any other comments on this revision of the standard?

   ☐ Comments:

For Example Only

For Example Only

Appendix F: SERC Consideration of Comments Form (Latest approved version of form is posted on the SERC website: www.serc1.org)

SERC [INSERT RSS NAME] Consideration of Comments on
[INSERT APPROPRIATE SERC REGIONAL RELIABILITY STANDARD TITLE & REV. #]

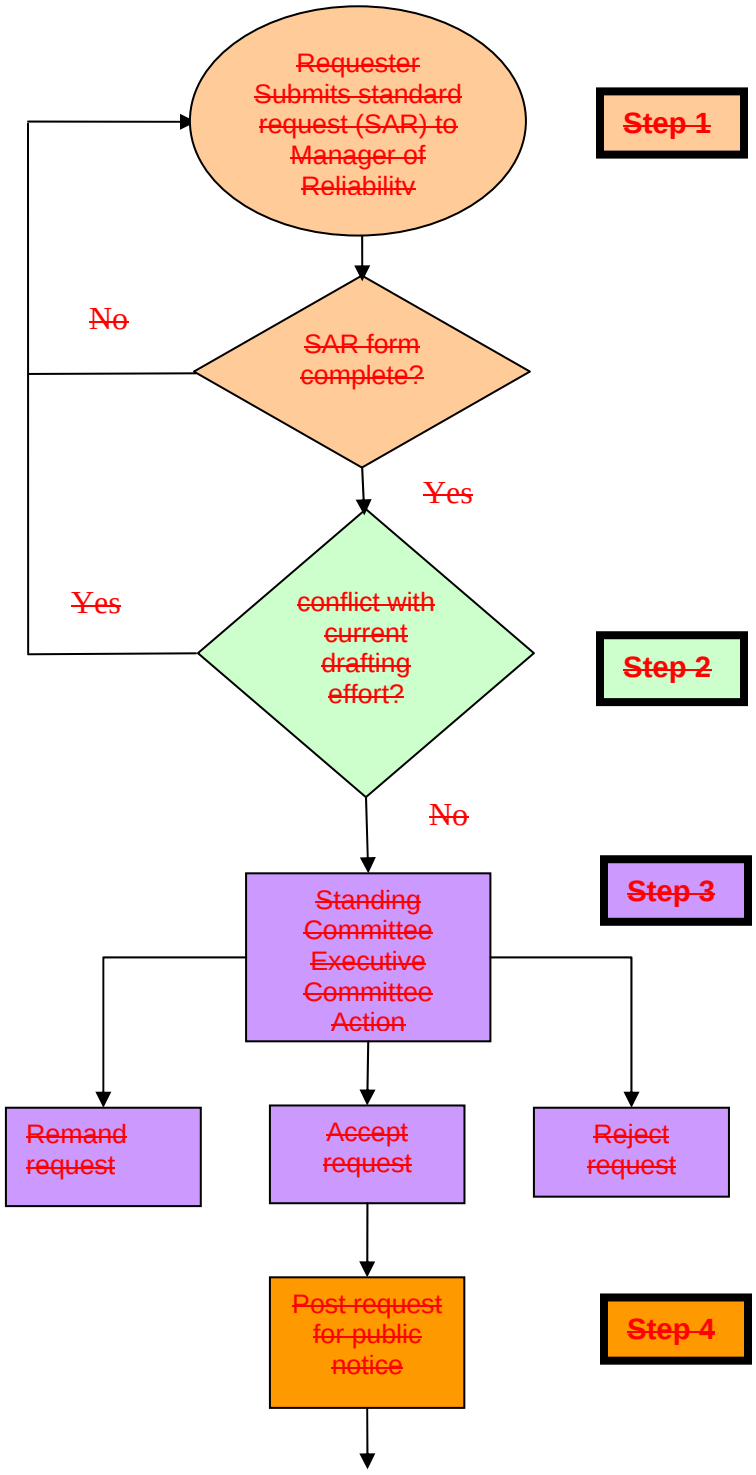
[SAMPLE LANGUAGE]
This document contains comments submitted on Revision [_] of the [Standard], which was distributed for review on [Date] in accordance with the SERC Regional Reliability Standards Process Manual. ~~-~~Comments were received from the following.

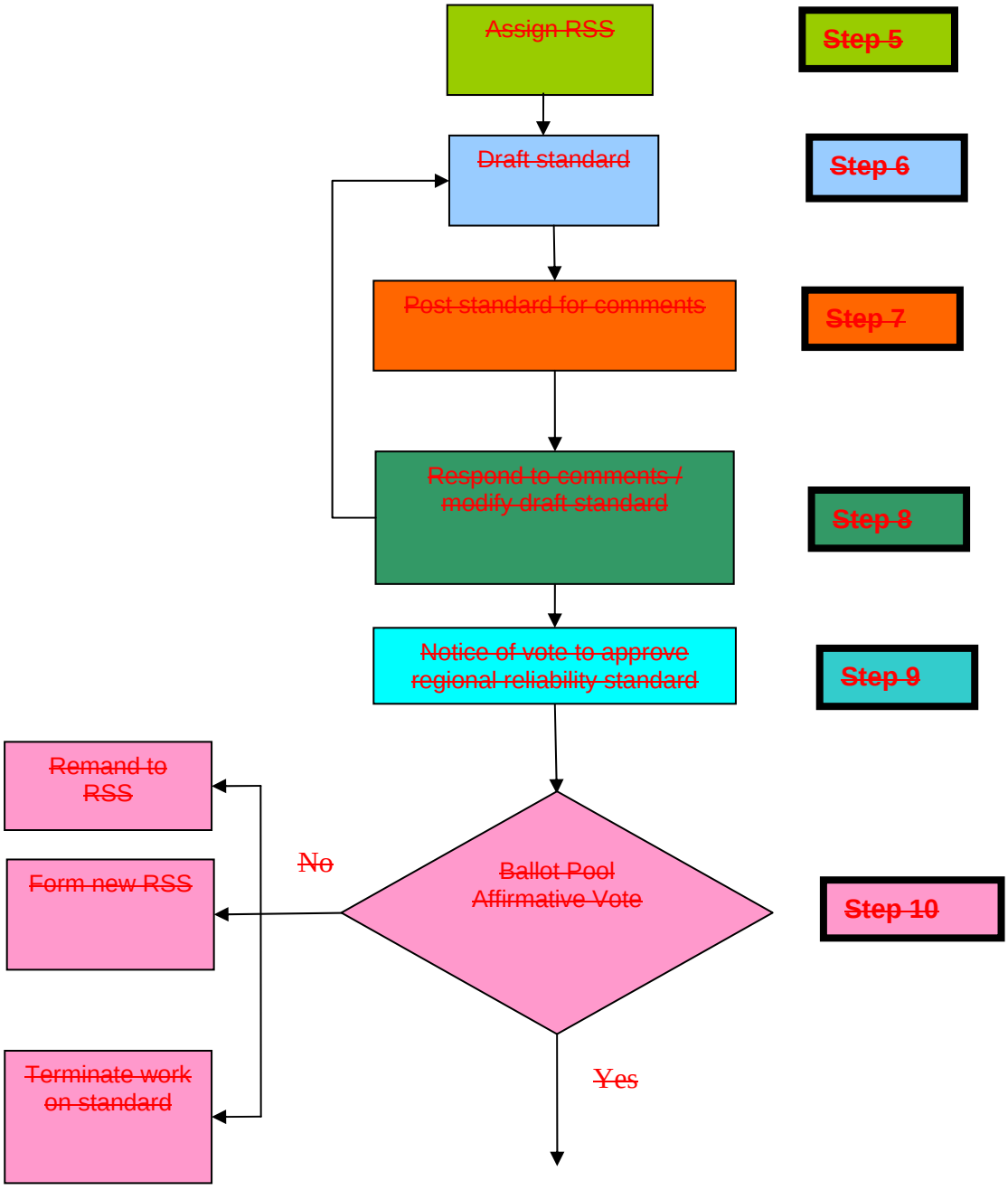
[INSERT INTRODUCTORY LANGUAGE AS APPROPRIATE]

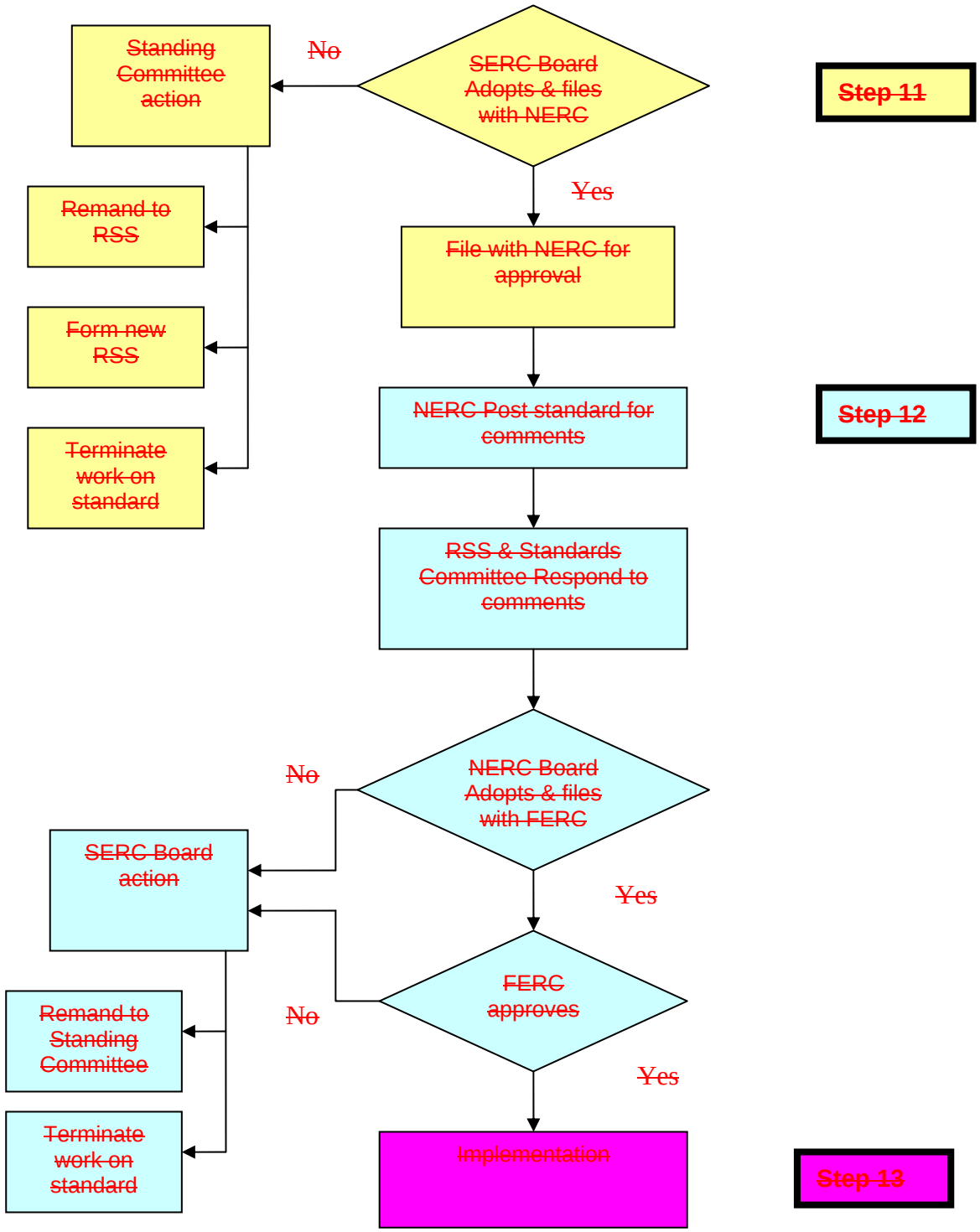
Commenter	Comment	Response

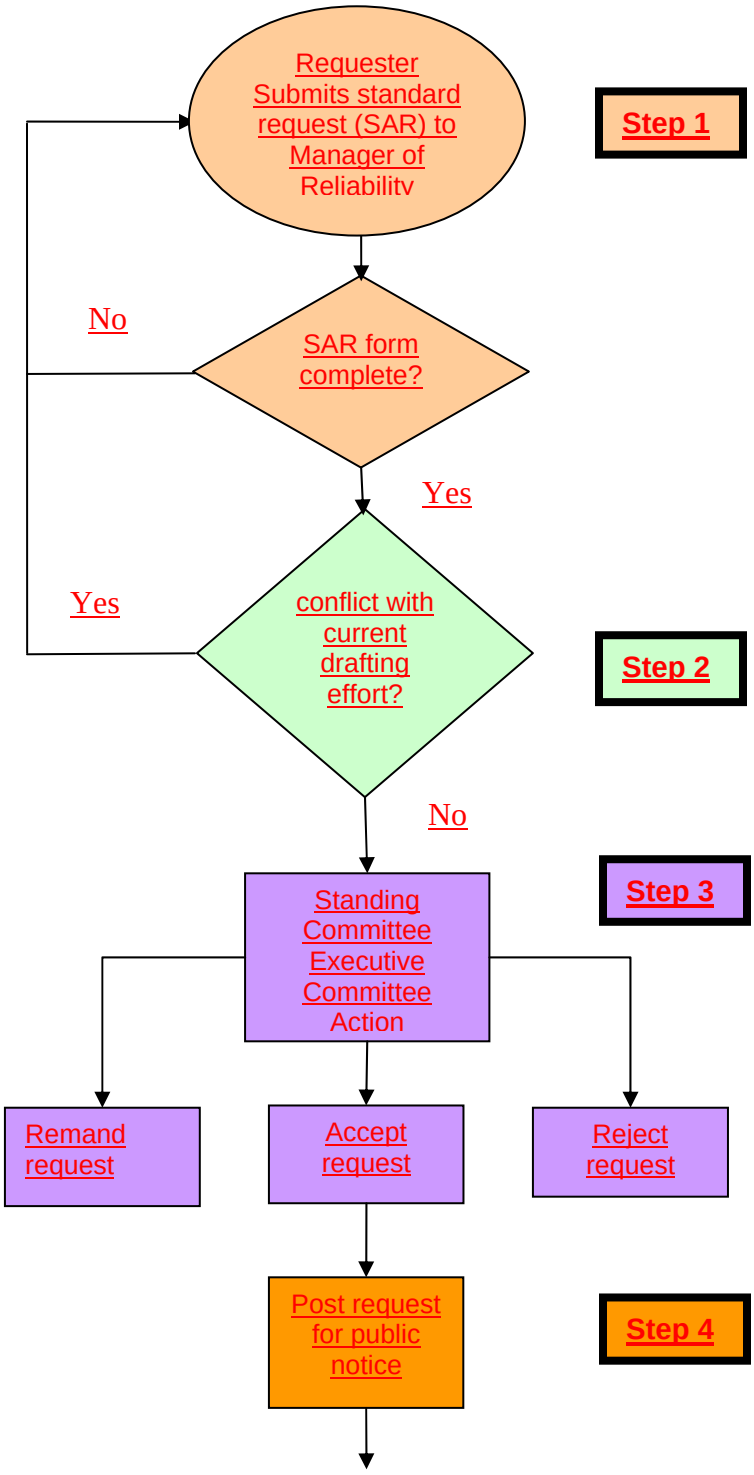
For Example Only

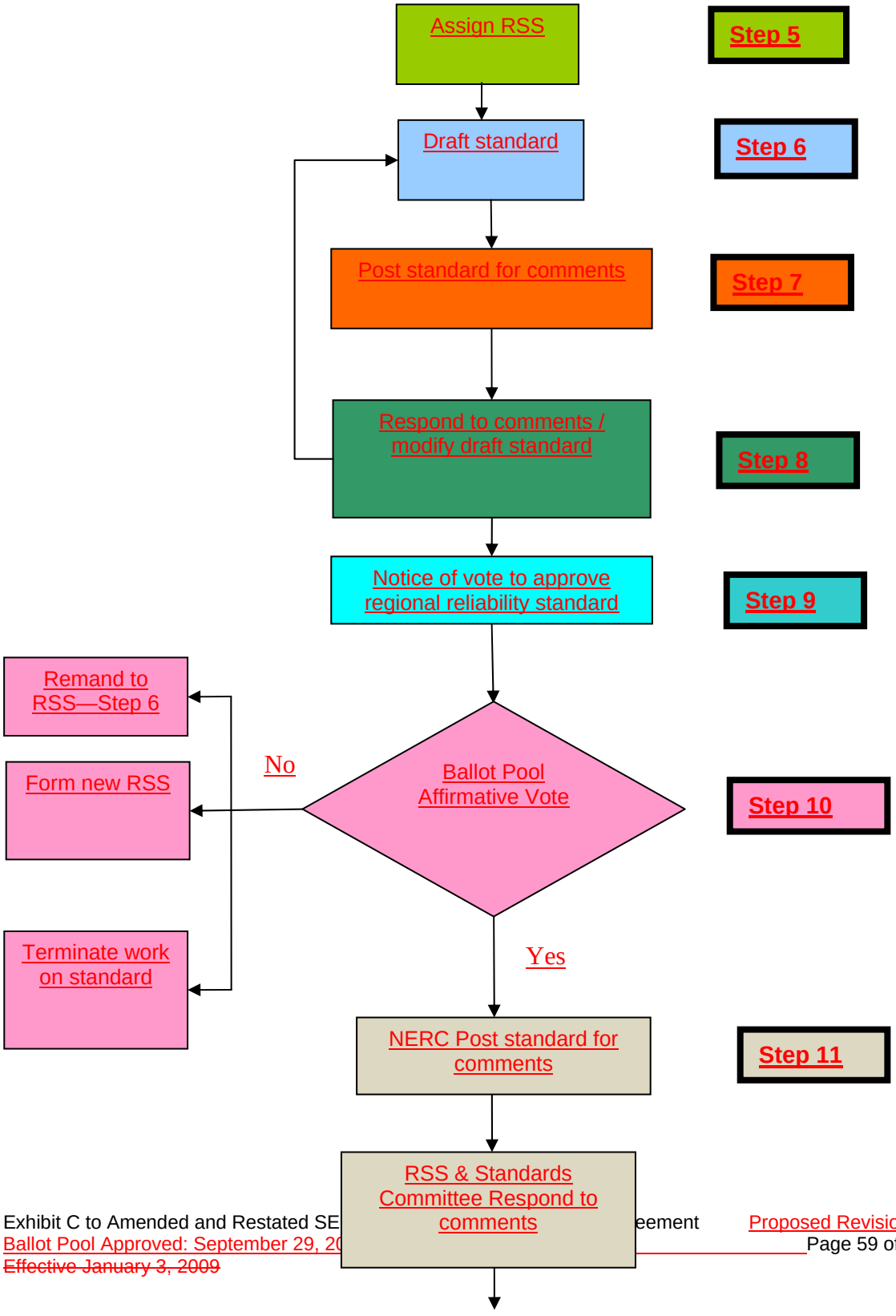
Appendix G: SERC Process Flow Diagram

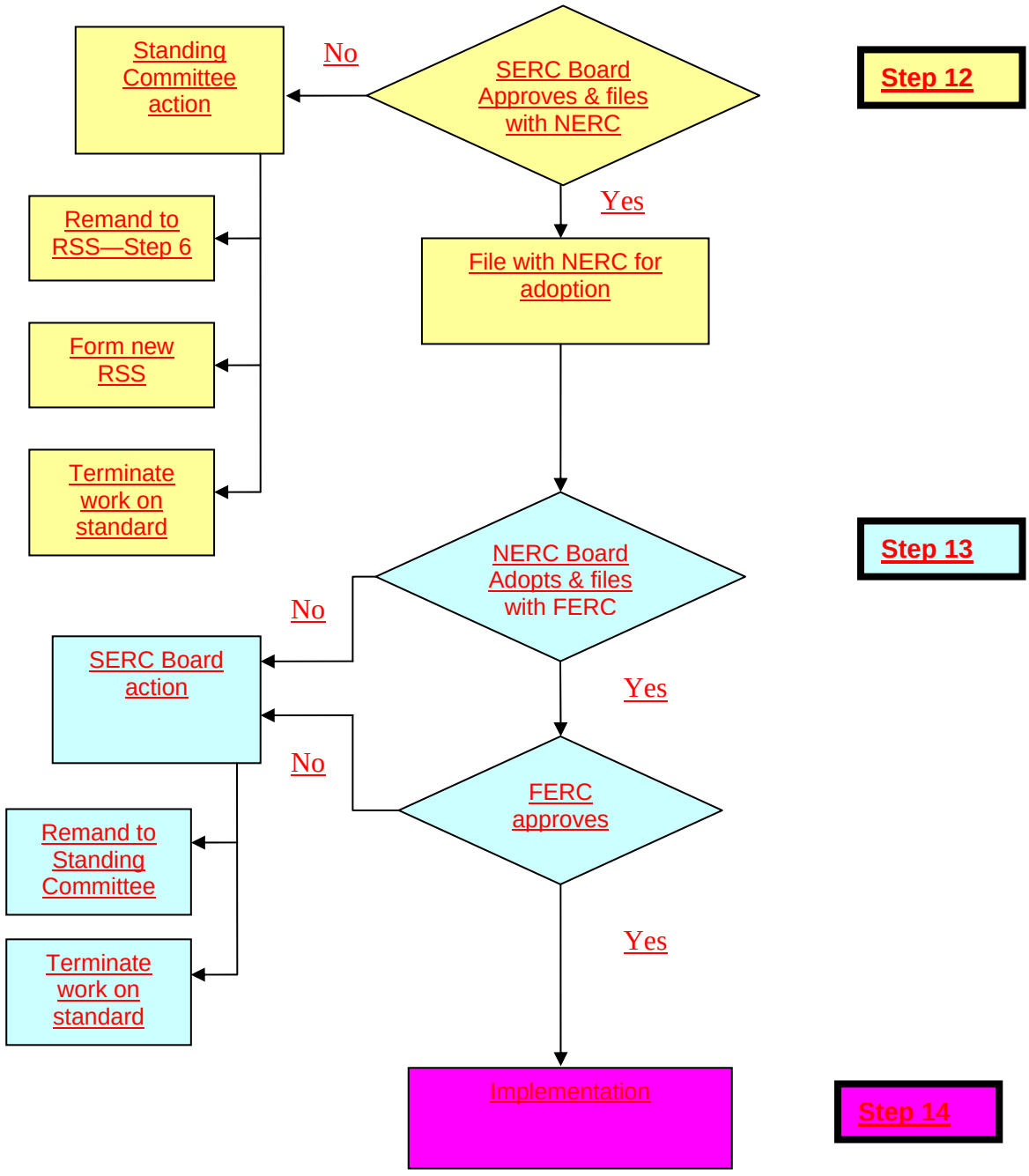

Requester Submits standard request (SAR) to Manager of Reliability
Step 1
No
SAR form complete?
Yes
Yes
conflict with current drafting effort?
Step 2
No
Step 3
Standing Committee Executive Committee Action
Remand request
Accept request
Reject request
Post request for public notice
Step 4


Assign RSS
Step 5
Draft standard
Step 6
Post standard for comments
Step 7
Respond to comments / modify draft standard
Step 8
Notice of vote to approve regional reliability standard
Step 9
Remand to RSS
No
Form new RSS
Ballot Pool Affirmative Vote
Step 10
Terminate work on standard
Yes


Standing Committee action
No
SERC Board Adopts & files with NERC
Step 11
Remand to RSS
Yes
File with NERC for approval
Form new RSS
NERC Post standard for comments
Step 12
Terminate work on standard
RSS & Standards Committee Respond to comments
No
NERC Board Adopts & files with FERC
SERC Board action
Yes
Remand to Standing Committee
No
FERC approves
Yes
Terminate work on standard
Implementation
Step 13


Requester Submits standard request (SAR) to Manager of Reliability
Step 1
No
SAR form complete?
Yes
Yes
conflict with current drafting effort?
Step 2
No
Step 3
Standing Committee Executive Committee Action
Remand request
Accept request
Reject request
Post request for public notice
Step 4


Assign RSS
Step 5
Draft standard
Step 6
Post standard for comments
Step 7
Respond to comments / modify draft standard
Step 8
Notice of vote to approve regional reliability standard
Step 9
Remand to RSS—Step 6
Form new RSS
Terminate work on standard
No
Ballot Pool Affirmative Vote
Step 10
Yes
NERC Post standard for comments
Step 11
RSS & Standards Committee Respond to comments


Standing Committee action
No
SERC Board Approves & files with NERC
Step 12
Yes
Remand to RSS—Step 6
File with NERC for adoption
Form new RSS
Terminate work on standard
NERC Board Adopts & files with FERC
Step 13
No
SERC Board action
Yes
No
FERC approves
Remand to Standing Committee
Terminate work on standard
Yes
Implementation
Step 14

From:	Pat Huntley
To:	rsg
Cc:	cipc_plus@list-serc1.org; ec_plus@list-serc1.org; oc_plus@list-serc1.org; "RBB@list-serc1.org"; "sc_roster@list-serc1.org"; rsg; Darrell Piatt; koneal@ferc.gov; "Leslie Saponaro"; nhenery@ferc.gov; serc comply; srogers@frcc.com; dp.skaar@midwestreliability.org; tim.gallagher@rfirst.org; sdochoda.re@spp.org
Subject:	SERC Regional Standards Development Procedure, Revision 2 Posted for Review by SERC Board of Directors
Date:	Tuesday, November 29, 2011 9:10:32 AM

To SERC Board of Directors:

The proposed Revision 2 of the SERC Regional Standards Development Procedure has been posted for a 15-day review period, as specified in the procedure (see below links). Approval of Revision 2 of the procedure is on the agenda for the SERC Board Executive Committee meeting on December 14, 2011.

Revision 2 of the SERC Regional Standards Development Procedure—Clean
Revision 2 of the SERC Regional Standards Development Procedure—Redline

Background:
The purpose of this revision is address issues identified during the SERC 2009 audit by NERC; make revisions to improve process efficiency and reduce the time required to develop a regional standard; and to ensure alignment with the NERC Standard Processes Manual, Revision 1 dated November 2010.

The proposed revision 2 received ballot pool approval on September 29, 2011. It has since been submitted for a 45-day NERC comment posting on process issues, as required by the NERC procedure to approve a revision to a regional standards procedure. The SERC drafting team developed responses to the comments received at their meeting on November 28, 2011. The SERC Standards Committee approved those responses on November 29, 2011.

In addition to the revised procedure, also posted are the SAR, Comments and Responses, a Summary of Proposed Changes, and other documents associated with development record (see below link).

Revision 2 of the SERC Regional Standards Development Procedure: Associated Documents

This notice is being provided for you information.

Cc: SERC CIPC Representatives and Alternates
SERC EC Representatives and Alternates
SERC OC Representatives and Alternates
SERC Registered Ballot Body
SERC Registered Entity Contacts
SERC Standards Committee
NERC Regional Standards Group
Timothy R. Gallagher
Daniel P. Skaar
Stacy Dochoda
Sarah Rogers

August M. McClaine
Manager, Member Services
SERC Reliability Corporation
2815 Coliseum Centre Drive
Suite 500

Charlotte, NC 28217
704-940-8203 (Office)
704-754-3389 (Cell)

This email and any of its attachments may contain SERC proprietary information that is privileged, confidential, or subject to copyright belonging to SERC. This email is intended solely for the use of the individual or entity to which it is addressed. If you are not the intended recipient of this email, you are hereby notified that any dissemination, distribution, copying, or action taken in relation to the contents of and attachments to this email is strictly prohibited and may be unlawful. If you receive this email in error, please notify the sender immediately and permanently delete the original and any copy of this email and any printout.

Y

Panel I, Written Remarks
Gerry Cauley, President and Chief Executive Officer
North American Electric Reliability Corporation

FERC Reliability Technical Conference
November 29, 2011

Good afternoon Chairman Wellinghoff, Commissioners, staff, and fellow panelists.

My name is Gerry Cauley and I am the President and Chief Executive Officer (CEO) of the North American Electric Reliability Corporation (NERC). It is NERC's mission to ensure the reliability of the bulk power system of North America and promote reliability excellence and accountability.

Identifying Priorities for NERC Activities

We initially gathered in February to identify reliability priorities for managing conventional and emerging risks. Today, as requested, I will address the four topics posed by the Commission:

a. What is the status of the priorities at the February technical conference? What are the most critical reliability issues and/or standards development initiatives that need to be addressed in 2011 and 2012? Has NERC's prioritization tool been useful?
b. One of the priorities was improving the compliance and enforcement process. How is that being addressed?
c. What are the biggest challenges to addressing these priorities and/or completing these initiatives in an effective and timely manner? What next steps are appropriate to timely and effectively address the priorities discussed?
d. How do NERC and reliability standards development teams incorporate in new or re-ordered priorities regarding reliability standards into their work plans? How emerging issues are considered and are any becoming high priorities?

2011 has been a challenging, but productive year. NERC moved forward on several priority initiatives, including standards prioritization, vegetation management, the definition of the Bulk Electric System (BES), critical asset identification, and reliability risk management. NERC has worked with the Commission to analyze lessons from major events, including the southwest cold weather event, the southern California event, and the severe snow event in the northeast. NERC announced a new compliance enforcement initiative, released reliability assessments addressing environmental regulations, a foundational report identifying new reliability performance measures, and root cause analysis methods that further enforce the setting of reliability priorities. NERC also conducted a grid security conference, an industry cybersecurity exercise, and moved forward on the development of cybersecurity standards. Twenty-two lessons learned and nine alerts have been posted this year. As noted in February, our goal is to develop a list of priorities to focus, up to a three year horizon, on areas most likely to have a positive impact on bulk power system reliability.

1. **Status of the Priorities Identified by NERC at the February Technical Conference**
In January, I outlined eight priorities for NERC, noting four specifically related to conventional risk management:

   i. Ensuring relay protection systems operate as expected and faults are cleared without unnecessarily tripping other equipment.

Status Update: One of NERC's top priority reliability issues is the misoperation of protection systems.[1] Nearly all major system failures, excluding the events caused by severe weather, include protection system misoperations as a factor contributing to event propagation. NERC's Transmission Availability Data System (TADS) and event analysis programs allow for the identification of simultaneous transmission line outages. Based on pooled information for 2008-2010, nearly one-third of all sustained automatic forced outages are dependent or common mode events. Though a number of protection systems are intended to trip three or more circuits, many events exceed planned protection operations needed to clear a fault. These events, especially those involving three or more automatic outages, are a high priority for NERC and the industry.[2]

The NERC-wide misoperation data for the second quarter of 2011 was received and the aggregated metric results have been posted on the NERC public reliability indicators web page:

- A total of 812 misoperations were reported for the quarter. Of these, 95 percent were designated as "unnecessary trips" and 5 percent as "slow or failure to trip." The most prevalent cause of unnecessary trips is "incorrect setting/logic/design errors," accounting for 35 percent of the total misoperations. This category includes "engineering" errors in protection system settings, documentation, and application, as well as uncoordinated settings and incorrect schematics

- Further analysis shows that 75 percent of the misoperations were associated with microprocessor-based relays, which are more complex than other technologies

In response to these findings, NERC formed a cross-functional team to develop a risk-informed response to include effective action steps. The goal is to achieve year-on-year misoperation reduction targets by deploying specific actions and tracking protection system performance. If suitable reductions are not realized, additional action plans will be developed toward meeting overall industry reduction goals.

Further, NERC has published, eight individual, *Relay Protection Systems Lessons Learned* in 2011 that address the following subjects:

- Special Protection Systems (SPS) maintenance precautions
- Relay Protection Systems coordination for close-in faults

[1] http://www.nerc.com/fileUploads/File/News/NERC%20President%20Top%20Priority%20BPS%20Reliability%20Issues%201-7-11.pdf

[2] http://www.nerc.com/files/2011_RARPR_FINAL.pdf

- Relay Protection Systems misoperations
- Power line carriers and misoperations
- Field revision to Relay Protection Systems
- Transmission Relaying – voltage transfer failure
- Transmission Relaying – removing unused components
- Use of out of date Relay Protection System technical prints

NERC continues to implement the System Protection Initiative, which addresses misoperation, relay loadability, protection system coordination, relay maintenance, analysis and mitigation of misoperations. Work is underway on five protection-related standards that address various aspects of protection systems. Standards on overall protection system reliability (redundancy) and disturbance monitoring are also pending.

In January 2011, NERC worked with Regional Entities to revise regional procedures based on the PRC-003 Reliability Standard, and developed a consistent approach to the collection[3] of misoperation information, along with systematic analysis and correction of the underlying causes. As a long-term solution, the ERO has placed a high priority on Reliability Standard Project 2010-05 to retire PRC-003 and revise the current PRC-004 Reliability Standard by modifying misoperation definitions and making reporting more consistent.

The Commission issued a notice of proposed rulemaking (NOPR) on PRC-023 addressing relay loadability this year and NERC filed comments in response to the NOPR on November 21, 2011. Additionally, NERC continues to prioritize addressing all the directives from Order No. 733 and Order Nos. 733A and B.

In addition, the Order No. 754 technical conference concerning the single point of failure issue has led NERC to undertake the development of a data request to determine the prevalence of and risk associated with this issue. NERC will make an informational filing with the Commission by March 15, 2012, addressing additional work in this area, and will follow up with status reports as needed once the data request has been issued, and responses have been received and analyzed.

As a long-term solution, the ERO has placed a high priority on Reliability Standard Project 2010-05 to retire PRC-003 and revise the current PRC-004 Reliability Standard by modifying misoperation definitions and making reporting more consistent.

ii. Ensuring field engineers and technicians modify system configuration, including protection and control settings, only after assessment of the consequences and after informing operating personnel when a change in configuration could temporarily set up a common mode failure.

Status Update: Along with the efforts mentioned above, a "rapid development" effort to address protection system misoperations is underway, and an interim data collection effort to

[3] http://www.nerc.com/files/2011_RARPR_FINAL.pdf
p://www.nerc.com/docs/pc/rmwg/Protection_System_Misoperation_Reporting_Template_Final.xlsx

uniformly measure the number of such events was implemented. NERC anticipates having a draft standard developed that will address system misoperations by August 2012 for presentation to the NERC Board of Trustees for approval.

In addition, NERC has initiated a new human performance program. Human error is often cited as the reason for almost 80 percent of all incidents and accidents in complex high-risk systems in many industries, including aviation, petrochemical, healthcare, construction, mining, and nuclear power industries. Many of the major events that occur in the bulk power system initially are labeled as human error. When the 80 percent human error is broken down further, the number reveals the majority of errors stem from latent organizational issues. The point of a human error investigation is to understand why people did what they did. It is the thorough analysis of events and near-misses, and the subsequent understanding of the root causes that allows organizations to prevent future occurrences.

The transfer of important reliability messages requires a variety of instruments that can advise practices and training, particularly those that can affect the reliability of the bulk power system. Sharing across the North American industry allows expertise and experience to strengthen the grid as a whole, making everyone more successful in meeting reliability objectives.

iii. Ensuring operating personnel use clear, unambiguous communications when issuing directives and communicating other operational information.

Status Update: Work is underway on a communications standard to move in the direction of three-part communication – a communication protocol where information is verbally stated by a party initiating a communication, the information is repeated back correctly to the party that initiated the communication by the second party that received the communication, and the same information is verbally confirmed to be correct by the party who initiated the communication.

iv. Preventing, non-random equipment outages, such as those caused by vegetation or objects within the safe clearance distance from energized lines, and common mode issues with generation, such as we saw during extreme cold conditions.

Status Update: Two significant efforts have occurred on vegetation management in 2011**.** On November 3, 2011, the NERC Board of Trustees approved the FAC-003-2-Vegetation Management Standard that was developed using a "results-based" model. Secondly, industry has done has been very responsive to NERC's 2010 alert on right of way clearances.

The proposed FAC-003-2 standard embodies a defense-in-depth approach to improving the reliability of the electric transmission system by requiring:

- Management of vegetation within the right-of-way to prevent vegetation encroachment into the flash-over clearance;
- Documentation of maintenance strategies, procedures, processes, and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods, and the inspection frequency;

- Timely notification of vegetation conditions that could cause a flash-over at any moment to the appropriate control center;
- Corrective actions to ensure that flash-over distances will not be violated due to work constraints such as legal injunctions;
- Annual inspections of vegetation conditions; and
- Completion of the annual work needed to prevent flash-over

This standard is expected to be filed with the Commission for approval in December 2011.

Right-of-Way Alert

In 2010, a vegetation contact by a Transmission Owner identified actual field conditions that varied significantly from design assumptions -- to the point where some facility ratings were considered inaccurate or in question. Follow-up resulted in the conclusion that this situation was not restricted to one entity or Region. As a result, NERC issued an alert (recommendation) on October 7, 2010, to proactively identify other such conditions and promote corrective actions. In this alert, NERC recommended that Transmission Owners review their current Facility Ratings Methodology for solely and jointly owned transmission lines to verify that the methodology used to determine facility ratings is based on actual field conditions.

During 2011, NERC provided guidance and information to alert recipients for performing assessments, including guidance and information regarding the prioritization of facilities. Review criteria were issued to industry in April. The assessment plan review criteria were used to guide Regional Entity staff in review of assessment plans and provide further assistance to the owners in meeting the intent of the recommendation. Two webinars were held, and NERC developed a semi-annual owner reporting spreadsheet to be used for reporting progress. For the July 15 report date, there were a total of 278 assessments completed.

On November 17, 2011, FERC issued an Order approving Reliability Standard FAC-008-3 (Facility Ratings), which presents clear, measurable, and enforceable requirements that obligate Transmission Owners and to develop facility ratings methodologies for their facilities.

2. Critical Reliability Issues and/or Standard Development Issues to be Addressed in 2011 and 2012 - Improving the Compliance and Enforcement Process

During 201, NERC focused on numerous reliability priorities, metrics, vegetation management, cybersecurity and a redesign of the standards process. Numerous taskforce initiatives also are underway, continuing the implementation of the 2010 *High Impact, Low Frequency Risk Report*, including the GMD task force and cybersecurity standards. One of the more significant efforts was the compliance enforcement initiative.

NERC's Compliance Enforcement Initiative

Compliance and enforcement process improvements in 2011 include new streamlining efforts and refinement of reporting mechanisms. From January to August, 2011, NERC implemented a new spreadsheet Notice of Penalty (NOP) format, known as the

Administrative Citation NOP that included minor, documentation or administrative violations. There were 285 violations filed in the eight Administrative Citation NOPs. The Commission did not review any violations that were filed in that format.

Building upon the success of the Administrative Citation NOP format, on September 30, 2011, NERC filed with FERC a *Petition Requesting Approval of New Enforcement Mechanisms and Submittal of Initial Informational Filing.* The petition included a description of NERC's new compliance enforcement initiative (CEI), by which the ERO can exercise its enforcement discretion to process possible violations pursuant to different tracks, according to risk. For FERC's information, the first group of 117 remediated issues that were processed under a new enforcement track referred to as Find, Fix, Track and Report (FFT). On the same day, in separate proceedings, NERC submitted 75 violations in a new spreadsheet Notice of Penalty (NOP) format, as well as 27 violations in three full NOPs. The Commission did not review any violations filed in the first spreadsheet Notice of Penalty or in the full Notices of Penalty that were submitted on September 30.

The CEI represents a more comprehensive and integrated compliance and enforcement strategy that differentiates and addresses compliance issues according to their significance to the reliability of the bulk power system. The goal of the CEI is to: (i) refocus industry efforts on achieving reliability excellence through attention to matters that pose risks to the reliability of the bulk power system; (ii) reduce undue regulatory burdens on users, owners and operators; and (iii) improve caseload processing.

Under the CEI, possible violations are still expected to be found, fixed, and reported to Regional Entities, NERC, and the FERC. Lesser risk issues that have been corrected will be reported to FERC as remediated issues in a FFT spreadsheet submitted for informational purposes only. Violations that pose a more serious risk will continue to be processed through to a NOP, either as a spreadsheet NOP or a full NOP, depending on the case. The spreadsheet NOP is an evolution of the Administrative Citation NOP format, using the spreadsheet reporting format for a larger group of violations.

The CEI represents a change in the way the ERO monitors compliance with and enforces Reliability Standards and is not limited to the September 30, 2011, filing. Going forward, the Regional Entities will continue to designate, and NERC will continue to file, remediated issues with FERC each month in an FFT informational filing. In the initial phase of CEI, auditors and other compliance staff will be able to recommend FFT treatment of certain findings, but the ultimate disposition will be determined by Regional Entity enforcement staff. In a second phase of CEI, which will be implemented at least 12-to-18 months after the September 30, 2011, filing and after significant training of compliance staff, staff will be able to designate certain findings for FFT treatment without enforcement staff oversight. NERC will have a series of webinars and workshops to guide compliance and enforcement staff at all levels on successful use of FFT.

On October 31, 2011, NERC filed its second FFT informational filing and its second spreadsheet Notice of Penalty. These remain pending before the Commission.

Notably, the CEI does not affect changes in the way that dismissals are identified or processed. Dismissals of violations occur when the Compliance Enforcement Authority (CEA) determines the particular issue does not constitute a violation of a NERC Reliability Standard, the entity is not subject to compliance with the standard at issue, or the particular issue is a duplicate of one already in process. One enhancement to the existing program is that NERC will publicly post certain dismissal information on its website. NOPs and FFTs are among the many tools of NERC to convey important compliance and enforcement information to the industry. NERC and Regional Entities utilize Lessons Learned, Compliance Application Notices, Compliance Application Reports, Case Notes and other bulletins, reports and newsletters. NERC and Regional Entities continue to host webinars, workshops and meetings to provide forums for discussion and dissemination of information. NERC and the Regional Entities are promoting a learning concept, and greater efforts are being devoted to educating the industry on expectations for compliance. NERC and Regional Entities are committed to ongoing outreach and educational opportunities.

3. Integration of Emerging Reliability Risk Issues into the Standards Prioritization Plan

As the ERO, NERC has developed risk control strategies and solutions by measuring the key, quantifiable components of bulk power system reliability. Refinement of risk control measures consists of calculated performance based on factual data. These measures are then weighted based on risk to reliability to further refine and identify trends and emerging issues. Additionally, NERC displays a quarterly updated set of reliability indicators on its website,[4] showing the ongoing status of bulk power system reliability.

NERC gathers information about system events to provide data needed to develop probabilistic risk information and trending. For example, NERC's Transmission Availability Data System (TADS)[5] began collecting forced outage information beginning in 2008, and will begin gathering industry information on unit generating outages through its Generating Availability Data System (GADS),[6] voluntarily provided since 1980, and provided in a mandatory fashion starting in 2012. In October, NERC launched the Demand Response Availability Data System (DADS) to provide a basis for projecting the affects of both dispatchable and non-dispatchable demand response on capacity planning and operational reliability. Demand response enrollment and event information will be collected and assessed on a semi-annual basis with summer and winter reporting periods.

Using event information, NERC has developed a reliability severity-risk curve, calibrated with real events representative of the risk to bulk power system reliability. Risk control goals include avoiding high-impact and medium-impact controllable risk. Based on objectives, industry action can be encouraged to meet risk control goals. The ultimate aim of NERC's risk control work is to illuminate the historical, overall bulk power system reliability landscape and reduce the risk to reliability by assessing robust data and tracking risk levels as indication of performance.

[4] http://www.nerc.com/page.php?cid=4|331
[5] http://www.nerc.com/page.php?cid=4|62
[6] http://www.nerc.com/page.php?cid=4|43

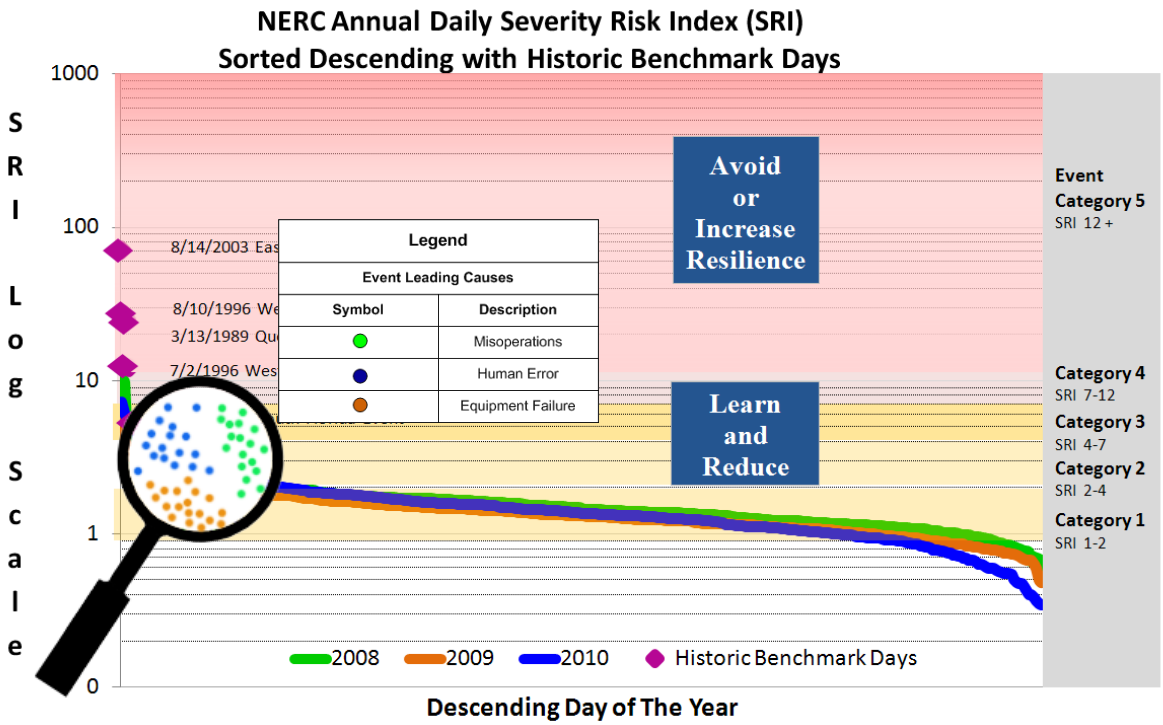
The four steps of the risk control cycle are to:

i. Identify risk clusters, connect contributing activities, and set risk measures to monitor performance improvement progress;
ii. Select the significant risk clusters as priority projects based on reliability impacts;
iii. Organize attention, resources and creativity around the priority projects and develop coordinated and multifunctional solutions; and
iv. Take actions, measure and demonstrate results.

NERC developed a risk control framework and performance measurement approach to identify specific problems and measurement of the impacts of industry activated solutions. Information and data gathered by NERC enables measurement of the risk to reliability using trend evaluation and detailed analysis supported by hard data, rather than anecdotal evidence.

NERC's premier foundational report *2011 Risk Assessment of Reliability Performance* report[7] provides an industry reference for historical bulk power system reliability, as well as analytical insights with a view to action. The key findings and recommendations provide targeted input to NERC's Reliability Standards and project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection. This foundational report will be produced annually, published in late spring, beginning in 2012. The findings will represent NERC's annual view of the state of reliability, supported by performance metrics and analysis, and will portray trends and measurement of the progress towards reliability improvement.

[7] http://www.nerc.com/files/2011RMWG_Annual_Report.pdf.



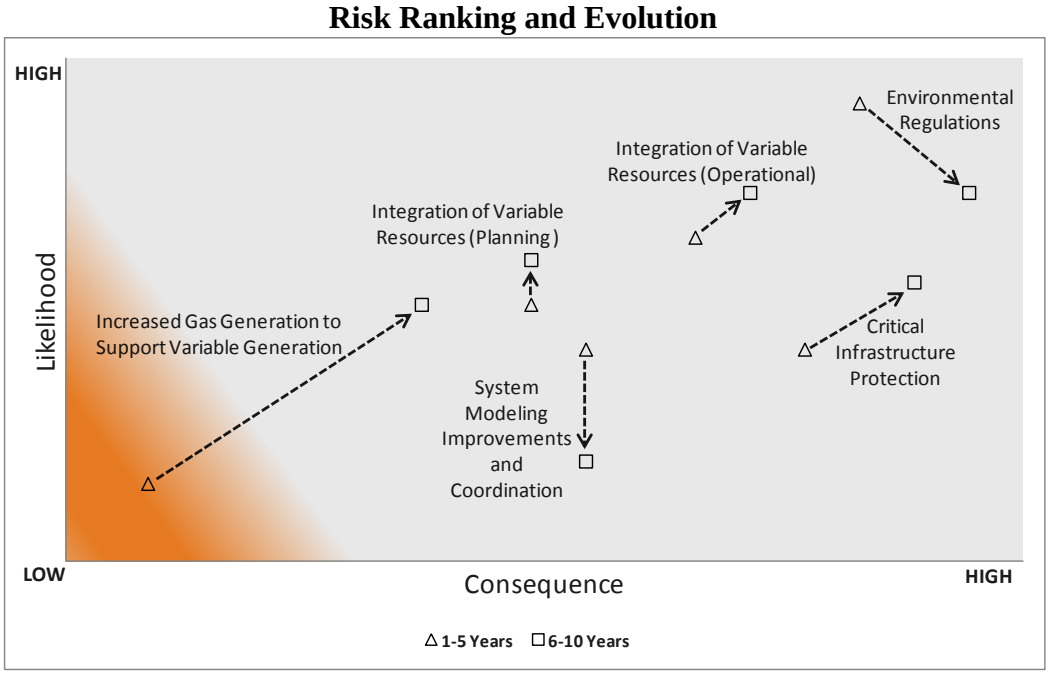
Additionally, NERC annually reviews, assesses, and reports on the overall electric reliability of the interconnected bulk power system in North America. As part of its seasonal assessments, NERC requests information pertaining to lessons learned in previous seasons. Preparations to address these seasonal elements are then evaluated and determinations made regarding industry readiness to address the lessons learned, along with the overall preparations to maintain bulk power system reliability.

Further, in its long-term reliability assessment, NERC identifies and analyzes the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes. For NERC's annual long-term reliability assessment, the risk from standing and emerging reliability issues is measured based on their perceived likelihood of occurrence and potential consequences to reliability of the bulk power system. For example, in the 2011 *Long-Term Reliability Assessment*, six emerging reliability issues have been identified:

2011 Emerging Reliability Issues

- Environmental Regulations and Impacts to BPS Reliability
- Integration of Variable Generation (Operational)
- Critical Infrastructure Protection
- Integration of Variable Generation (Planning)
- System Modeling Improvement and Coordination
- Increased Gas Generation to Support Variable Generation

Risk Ranking and Evolution[8]



[8] The risk vectors resulting for the likelihood and consequence ranking for each of the emerging or standing reliability issues are developed for both the one to five (1-5) year and six to ten (6-10) year timeframes are shown below (see figure below). Risk vectors for the 1-5 year timeframe are represented by a diamond—the 6-10-year risk vectors are represented by the square. With this perspective, relative risk of each issue is determined based on the Planning Committee survey results. Shifts in relative risk can be measured by evaluating the change between the two time periods.

Issues identified in the upper-right quadrant of the figure are considered to be high-likelihood of occurrence and high-consequence to the reliability of the bulk power system. This risk assessment is completed each year and acts as a platform to inform stakeholders, regulators, policy makers and the general public what issues NERC believes need to be most critically addressed.

Further, for issues identified as high-likelihood of occurrence and high-consequence to the reliability of the bulk power system, a detailed special reliability assessment can be completed to further understand the implications to reliability. Scenario analysis also can be performed to assess the robustness of the reference case against the scenario results, and to determine how the issues affect bulk power system reliability. The most recent examples are the assessment of resource adequacy impacts from potential environmental regulations and integration of variable generation.

Recommendations to augment or modify NERC's Reliability Standards can result from these Special Reliability Assessments. For example, the integration of variable generation activity has provided direct input into NERC's Modeling and Data Standards (MOD) and a host of additional recommendations have been made for use in standards prioritization.

4. NERC's Progress on High-Impact, Low- Frequency Risks

Beginning in the third quarter of 2010, NERC began following the ESCC's Critical Infrastructure Protection Roadmap[9] with activities outlined in NERC's Technical Committee's Critical Infrastructure Strategic Initiatives Coordinated Action Plan.[10] These activities included organizing four task forces:

- Cyber Attack Task Force
- Geomagnetic Disturbance Task Force
- Severe Impact Resiliency Task Force
- Spare Equipment Database Task Force

Each task force has made significant progress toward its goals. For example, at its November 3, 2011 meeting, NERC's Board of Trustees approved the Special Report: *Spare Equipment Database*, which provides a platform for the re-development of a voluntary, industry-wide Spare Equipment Database (SED). This database initially will focus on providing an inventory of critical transmission and generator start-up transformer spares managed by North American bulk power system Transmission and Generation Owners. Gathering information to support the database is expected to commence in the second quarter of 2012.

The affects on the bulk power system from Geomagnetic Disturbances continue to be a topic of interest in many public forums. Recognizing the resiliency of the bulk power system to disturbances is extremely high, this potential vulnerability will require an understanding of what additional resiliency and design improvements are required to maintain bulk power system reliability. I have spoken to Congress, as well as at the NERC sponsored

[9] http://www.nerc.com/docs/escc/ESCC_Critical_Infrastructure_Strategic_Roadmap.pdf

[10] http://www.nerc.com/docs/ciscap/Critical_Infrastructure_Strategic_Initiatives_Coordinated_Action_Plan_BOT_Apprd_11-2010.pdf

geomagnetic disturbance workshop in April and various forums on NERC's activities and our approach to determine system vulnerability and integrated solutions. NERC's industry workshop[11] provided an opportunity for industry input into NERC's activities on preparation and mitigation actions to inform industry on potentially heightened precautions they could consider to minimize the risk to the bulk power system from severe geomagnetic disturbances. Further, the workshop provided an opportunity for industry input in an *Industry Advisory Alert* on geomagnetic disturbances,[12] which provided a set of operational and planning actions to prepare for the effects of a severe Geo-Magnetic Disturbances (GMD) on the bulk power system.

The Geomagnetic Disturbance Task Force has focused on:

- Equipment vulnerability, including transformers, breakers, relaying, capacitive/reactive elements and generation
- Geomagnetic disturbance space storm wave fronts, and expected intensity levels for a one-in-one hundred year frequency level, along with latitudinal risk
- Integrated planning and operating solutions to strengthen system response

A report with recommendations and next steps will be sent to the Planning, Operating and Critical Infrastructure Committees in December 2011, with a final Board of Trustees approval expected in the first quarter of 2012.

Meanwhile, the Cyber Attack Task Force will send its first draft report to the Critical Infrastructure Protection Committee meeting in December, and the Severe Impact Resiliency Task Force will provide its first draft at the March 2012 Operating Committee meetings.

5. Cybersecurity Initiatives and Standards

Work to secure the grid is ongoing and will continue into the future. The ability to provide industry with key information on a timely basis remains a top priority. NERC, through the ES-ISAC, issued alerts to the industry addressing cyber attacks exploiting RSA Secure ID authentication, Stuxnet and Night Dragon. The system is well known by industry, handles confidential information and does so in an expedited manner. NERC sponsored the Grid Security Conference to advance information sharing and education between NERC, the government and the electricity industry. More than 20 educational sessions were scheduled on topics ranging from Advanced Persistent Threat, Industry Best Practices in Grid Security, and Electric Facility Threats and Violence. With wide representation from organizations across the United States and Canada, the conference provided security professionals with real tools and information that they can take back to their companies and improve their security posture.

NERC also recently completed the first grid cybersecurity readiness exercise. With more than 75 government and industry partners participating, the two day exercise assessed NERC and the industry's crisis response plans to validate current readiness in response to a cyber

[11] See GMD Workshop Proceedings at http://www.nerc.com/docs/pc/gmdtf/GMD_Workshop_Report_April_2011.pdf

[12] http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2011-05-10-01_GMD_FINAL.pdf

incident. The conference and the exercise enhanced collaboration between NERC, the industry and government stakeholders.

NERC filed a petition for approval of the CIP Version 4 Reliability Standards with FERC on February 10, 2011. The CIP Version 4 standards were developed in response to directives in Order No. 706[13] and propose to modify CIP-002-3 to include bright-line criteria for the identification of Critical Assets, replacing the current entity-developed risk-based assessment methodology in CIP-002-3. NERC also developed conforming changes to the seven remaining CIP Version 4 Reliability Standards.

The CIP Version 4 standards serve as an interim step to addressing the complete set of directives in Order No. 706. NERC anticipates responding to all of the Order No. 706 directives in the CIP Version 5 standards, which currently are under development.

The proposed CIP Version 5 standards collapse the steps of identifying Critical Assets and Critical Cyber Assets into a single step of characterizing "BES Cyber Systems" as "High Impact," "Medium Impact," or "Low Impact" based on the impact of cyber systems to the reliable operation of the bulk power system. This characterization makes use of a bright-line concept similar to Version 4, but rather than the two-step process, requires responsible entities to determine the impact of loss, compromise, or misuse of a given BES Cyber System to a bright-line impact filter.

Other notable features of the proposed CIP Version 5 standards include that they are expected to:

- Reduce technical feasibility exceptions
- Provide for developing consistent identification criteria of BES Cyber Systems and application of cyber security requirements that are appropriate for the risk presented to the BES
- Provide for developing requirements that foster a culture of security and due diligence in the industry
- Provide guidance and context for each standard requirement
- Develop a realistic and comprehensive implementation plan for the industry
- Leveraging current stakeholder investments used for complying with existing CIP requirements.

NERC anticipates filing the proposed CIP Version 5 standards with the Commission for approval in the third quarter 2012, pending a successful industry ballot and NERC Board of Trustees approval.

6. Redesign of the Standards Development Process to Improve Throughput Timelines and Quality

As announced in the February conference, NERC's Board of Trustees approved actions to improve the pace of the standards process. As noted then, NERC continues to examine and implement new ways to further expedite the development process.

[13] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, *order on reh'g*, Order No. 706-A, 123 FERC ¶ 61,174 (2008).

The NERC Standards Committee was granted authority to expedite the standards development process. Methods for expediting this process include:

- Shortening the 45-day formal comment period;
- Shortening the 30-day period for forming the ballot pool;
- Allowing significant modifications following the initial ballot without the need for another formal comment period provided the modifications are highlighted before conducting any successive ballot; and
- Shortening any of the 10-day ballot windows

One area of focus was shortening the time needed to develop an initial draft of a proposed standard. With a goal of developing a standard in a year, NERC piloted a "rapid development" project that uses a small team to develop the first draft of a standard for posting along with the Standard Authorization Request (SAR). The SAR and draft standard will then be formally submitted to the Standards Committee for posting, consistent with the Standard Processes Manual approved by FERC.

Additionally, rather than developing an interpretation and making revisions later to the same standard, the Standards Committee developed a "rapid revision" process for addressing interpretations by making a permanent revision to the standard. Responses to interpretation requests are limited to a standard of strict construction based on the language in the standard; however, there are often times when a change to the language in the standard would be more effective than developing an interpretation. As envisioned, the timeline for developing a successful "rapid revision" is accomplished within six months. A trial of this rapid revision process is underway for an interpretation request of the MOD-028-1 standard, and is expected to be presented to the Board of Trustees in February 2012.

NERC staff has provided legal and compliance personnel to review draft standards and provide feedback to standard drafting teams. This improves the overall quality of standards before they are posted for formal comment periods.

A strategic review of the full standards process has been initiated to assess other efficiency opportunities, while adhering to the general principles set out in the NERC Rules of Procedure, with a goal of filing with FERC for approval before the end of 2012.

7. NERC's Prioritization Tool Has Been Useful

NERC's prioritization tool was enhanced in 2011 to evaluate a project based on its reliability impact, time sensitivity, and practicality. The tool has been useful at ranking identified standards development projects and at providing information to help establish appropriate resource allocation. The tool provides a transparent way to accomplish this goal.

The Standards Committee has responsibility for establishing standards development project prioritizations and making modifications as appropriate to ensure the industry is allocating resources to achieve established goals. The prioritization tool has been helpful in serving as an aid in the prioritization effort. The Standards Committee's intention is to continually improve and refine the tool to address those issues of greatest importance to the industry.

NERC also is working to improve the prioritization effort by factoring in such issues as cost/benefit in increasing stakeholder participation in analysis of individual projects.

The prioritization tool will continue to be effective in ranking planned and identified standards development projects as it has during the development of the last two versions of the Reliability Standards Development Plan. However, the prioritization tool is only one factor in the development of the ERO standards development priorities, and additional factors must be considered. NERC is investigating processes for formally triaging incoming issues to determine how and when a standards related response is the best approach for addressing the reliability risk associated with emerging issues.

8. **Biggest Challenges to Addressing Priorities in an Effective and Timely Manner**
This year saw a significant focus on prioritization throughout NERC. Whether through the standards prioritization process, the compliance enforcement initiative, the GMD task force, or cybersecurity standards, we have moved forward with an aggressive schedule. The biggest challenge to completing priority standards is managing issues that come up during that year that are of importance to NERC, its stakeholders and FERC, while maintaining a focus on priorities. Resource allocation is always a concern, and the Commission's support of NERC's budget is helpful.

Overall, ongoing dialogue with the Commissioners and their staff helps facilitate increased understanding and communication of NERC initiatives and priorities. Participation of Commissioners and their staff at NERC board meetings offers a better understanding of NERC initiatives and priorities.

Conclusion

Although less than a year has passed since our last conference, I am pleased to report the progress on many of the priorities we discussed in February. There is more to do. As always, you have my commitment to work with you in partnership to ensuring the reliability of the bulk power system. I thank you for your attention and look forward to your questions.

Panel II, Written Remarks
Gerry Cauley, President and Chief Executive Officer
North American Electric Reliability Corporation

FERC Reliability Technical Conference
November 29, 2011

Good afternoon Chairman Wellinghoff, Commissioners, staff, and fellow panelists.

Incorporating Lessons Learned into a More Reliable Grid

For today's second panel, you have asked us to address how lessons learned are incorporated into NERC priorities. Specifically:

a. How do lessons learned from events analysis get disseminated to industry?
b. How do NERC's non-standards process such as industry alerts, compliance application notices interact with the reliability standards? To what extent do these processes aid in identifying important reliability matters that are not addressed under the existing Reliability Standards?
c. Is the alerts process getting the message out on issues of immediate importance?
d. How do you gauge whether industry is appropriately implementing NERC alerts or lessons learned from an event analysis?
e. Is there a feedback loop into the Reliability Standards development process to determine if there is a gap in the standards? If so, how has that been working? If not, should there be?

While NERC's Reliability Standards provide the foundation for bulk power system reliability, NERC's Compliance and Enforcement activities are tools needed to ensure reliability. NERC strives to create an environment in which reliability is not only sustained, but improved. A key component of this environment is an industry that continuously learns from itself and others, and deploys, as practical, those elements that will provide effective reliability risk controls into the future.

As one element of a learning organization, NERC's event analysis serves an integral function of providing insight and guidance by identifying and disseminating valuable information to users, owners, and operators of the bulk power system that enables improved reliability performance.

Since January 2010, NERC has significantly increased both the volume and quality of information to the industry in response to three major factors: 1) industry's request for more information to understand compliance; 2) NERC's commitment to improve openness and transparency; and 3) NERC's vision of being a learning organization and working collaboratively internally, with the Regional Entities and with industry, to focus on reliability issues.

There are a number of ways to support industry learning and provide guidance. NERC provides a variety of communications and documents meant to support an industry learning environment.

For example, NERC has focused on Compliance Application Notices, Lessons Learned, and Alerts, including what role they play, whether the processes for these communications are working, and whether any gaps exist, to provide multiple channels for transparent information flow to industry and energize organizational learning on bulk power system reliability activities.

To assist in these efforts, NERC has developed several resource materials to aid in transparency, communication and consistency:

i. Directives - Directives are guidance provided from NERC to the Regional Entities on conducting delegated activities pursuant to the Regional Entity delegation agreements.
ii. Compliance Analysis Reports (CAR) - CARs are analyses of standards that have experienced a high frequency of violations, as well as analyses of registration appeals and organization certification. These reports provide statistical information regarding violations as well as insight on potential causes of the violations.
iii. Compliance Application Notices (CAN) – CANs provide instructions for NERC and Regional Entity Compliance Enforcement Authority (CEA) staff, which includes auditors, investigators, and enforcement staff, regarding how to assess compliance. They also provide transparency on that instruction to industry.
iv. Reliability Standard Audit Worksheets (RSAW) - The RSAW provides a non-exclusive list, for informational purposes only, of examples of evidence a registered entity may produce or may be asked to produce in their demonstration of compliance with a Reliability Standard.
v. Key Reliability Spot Check Program Reports (KRSSC) –The KRSSC Program is a valuable tool in assessing and identifying consistency issues in the application of key Reliability Standards across the eight Regional Entities. Assessment of inconsistencies allows NERC to provide the proper guidance to the Regional Entities and registered entities which, improves the compliance monitoring process.
vi. Bulletins (Public Notices) – Bulletins provide information to NERC and Regional Entity staff and/or industry.
vii. Case Notes – Case Notes provide information on approved mitigation plans to industry. These mitigation plans are associated with enforcement actions that are still being processed and that may be resolved by dismissal, Notices of Penalty or Find, Fix, Track and Report (FFT) Remediated Issue Informational filings. Therefore, they provide information well before the corresponding violation is fully processed. Information regarding these mitigation plans and activities is provided in a redacted form.
viii. Dismissal Analysis – The dismissal analysis provides information to registered entities on common reasons for dismissals.
ix. Annual Compliance Monitoring and Enforcement Program (CMEP) Report – This report provides an overview and analysis of the previous year's CMEP activities.
x. Annual Actively Monitored List (AML) – A registered entity is required to be compliant with all applicable reliability standards. The AML is issued every year to provide a base subset of standards that are to be actively monitored. An audit scope may be expanded or reduced from this list.
xi. Annual Electric Reliability Organization (ERO) CMEP Implementation Plan - The ERO CMEP Implementation Plan is the annual operating plan for compliance monitoring and enforcement activities.

xii. Annual Audit Schedule – Provides notification of upcoming audits.

xiii. Enforcement - Find, Fix Track (FFT) and Report Spreadsheet – The FFT spreadsheet, introduced as part of NERC's Compliance Enforcement Initiative in September 2011, is one of the newest streamlining initiatives to resolve lesser (minimal to moderate) risk issues. It contains Remediated Issues that must be mitigated and a statement of completion of mitigation activities provided by the registered entity. They are tracked as part of a registered entity's compliance history. Inclusion of issues in the FFT informational filing at FERC represents closure of the enforcement action by NERC and the Regional Entities, subject to later verification of completion of mitigation activities, as warranted.

xiv. Enforcement - Administration Citation Notice of Penalty Spreadsheet – This spreadsheet, used between January and August 2011, contained minor, administrative, or documentation violations that posed a minimal risk to the reliability of the bulk power system. This also represents an early 2011 streamlining initiative.

xv. Enforcement - Notice of Penalty Spreadsheet – This spreadsheet provides a list of low to medium risk compliance issues disposed with reduced enforcement processing. This spreadsheet built upon the successful implementation of the Administrative Citation Notice of Penalty. It was another streamlining initiative that was introduced by NERC in September 2011. It contains more serious (minimal to moderate) risk issues.

xvi. Enforcement - Full Notice of Penalty – The most serious risk issues are filed in Full Notices of Penalty. They also may be used with respect to minimal to moderate risk issues, as needed to convey more detailed or specific information in support of the disposition of the underlying violation. – Violations with medium to high risk are disposed through a full Notice of Penalty and complete enforcement process.

NERC realizes that while these materials have their benefits, providing volumes of information can lead to entities focusing more on managing compliance risk than focusing on reliability risks. Therefore, NERC continues to work with entities on activities, such as the compliance enforcement initiative, to address low to medium risks to reliability in a more efficient manner, thereby enabling registered entities to spend more time focusing on high risk priorities.

1. Compliance/Compliance Application Notice

One of most well known of all these materials is the Compliance Application Notice (CAN). NERC currently has 16 CANs posted as final on its website and anticipates having approximately 25 posted by the end of 2011. CANs were developed for the purpose of creating consistency of compliance application across all NERC and Regional Entities and to provide transparency to industry. NERC has produced CAN's on several topics. CAN-0016 provides instruction for assessing whether registered entities have developed sabotage reporting procedures that fulfill the requirements of CIP-001 R1. CAN-0018 provided instruction for assessing what equipment should be considered "terminal equipment" under FAC-008 and has been revised to reflect specific series connected terminal equipment.

CANs do not expand the scope of a Reliability Standard, and the importance of this was discussed during the August 3, 2011 Member Representatives Committee (MRC) in Vancouver. As a result, the NERC Board of Trustees (BOT) provided guidance regarding CANs to NERC staff. In response to that guidance, NERC is in the process of redrafting all

of the CANs that had been previously posted as final to target the instruction to Compliance Enforcement Authorities (CEA's) instead of industry. NERC staff has expanded the process to include more industry input and transparency and is seeking to define, wherever applicable, a range of acceptable actions that meet the requirements of the standard. As part of the process revisions, NERC staff continues to provide greater information regarding how the compliance application was determined and its rationale for adopting or not adopting industry comments.

There is still work needed to gain industry acceptance for CANs. As acceptance of the CANs grows and industry understands that CANs are an ERO activity relating to the *compliance* aspect of the cycle, not the *standards* aspect of the cycle, NERC continues to receive feedback that, there should be a stronger link to the standards development process. To that end, NERC staff encourages "CAN Prevention" to standards drafting teams, with the goal that the teams will consider compliance monitoring and thus draft the standards as clearly as possible including compliance monitoring provisions. While the need for CANs may never be completely eliminated, it can be greatly reduced if the standards are first written in a way that provides for more consistent compliance application.

NERC is supportive of revising a standard but cannot wait until it becomes mandatory and effective to monitor compliance. NERC believes it can provide instruction to CEAs in order to facilitate consistent assessments of compliance and to make those instructions transparent to industry so it is aware of how a CEA will assess compliance during an audit or spot check. Additionally, NERC recognizes the expertise of industry. As NERC becomes more transparent regarding the compliance expectations for standards as currently written, the collective experience and expertise of the industry must be considered and balanced with the understanding that NERC, as the ERO, has an enforcement responsibility that requires independence in enforcing the currently approved standards.

2. Events Analysis

NERC is responsible for conducting an event analysis when serious events occur on the system to understand why they happened and what needs to be done to address the causes. NERC's goal is to shine a light on what the problems are and to make sure it doesn't happen again.

NERC's event analysis process reviews numerous events that occur on the bulk power system. These events can range from loss of a single component to loss of large amounts of load or generation. The events analysis process provides us with a path to learn from what happened with the goal of sharing those lessons with others to prevent it from happening again.

As part of this process, working with teams in each of the eight regional entities, NERC experts have analyzed a variety of events. System owners and operators are required to report the occurrence of defined bulk power system disturbances and unusual occurrences to the applicable Regional Entity and NERC in accordance with reliability standards and other

requirements. Each of these standards specifies timeframes within which initial and final event reports are required. Additional reporting requirements may also be required.

Operators of the system, Regional Entities and NERC need to become aware quickly of events and disturbances that take place throughout the bulk power system. This 'initial impression' information and insight are produced and delivered quickly and made available to personnel with planning and operations responsibilities across the system. This initial information sets forth a workable structure for very short-term analyses and reports, which can be followed by more intensive studies.

Once an event analysis is completed, the publishing of industry-developed lessons learned from these analyses serves an integral function of providing insight and guidance by identifying and disseminating valuable information to owners, operators and users of the bulk power system (BPS). I do believe NERC, working with the Regional Entities and industry, needs to develop a mechanism to better track and ensure closure of those issues identified to be addressed. It is essential to ensure we don't repeat the errors of the past and ensure accountability on a going forward basis.

3. Lessons Learned

NERC's role as the ERO facilitates a vast and unmatched capability for access to event data and information, which allows for a varied library of lessons learned. The leveraging of industry experiences and preventative measures is a proactive way of preventing events from re-occurring or from happening at all. Lessons learned are publications that originate and are developed by registered entities that are impacted by events and disturbances on the BPS. The key elements include the corrective actions taken, the innovative solutions used, and the primary lessons institutionalized by the submitting entity. The lessons learned are then submitted to NERC for publication and sharing with the industry. There are times in which NERC or the regional entities will develop lessons learned from trends or observations of consolidated event information.

Since April of 2010, NERC has published 45 individual lessons learned that were developed from recorded analysis of events captured in the ERO event analysis program. There have been 79 lessons learned candidates submitted in the first three quarters of 2011, and those submittals are in various levels of the drafting process. These publications are announced formally and posted for industry consumption on the NERC web site.

As an example, 55 lessons learned were submitted by entities impacted during the February 2011 cold weather event in Texas and the Southwest. These lessons were consolidated into 22 separate lessons for publication. Several themes addressed in these lessons are as follows:

- Generating Unit Temperature Design Parameters and Extreme Winter Conditions
- Adequate Maintenance and Inspection of Generator Freeze Protection
- Plant Instrument Transmitters and Sensing Equipment Freezing Due to Heat Trace and Insulation Failures
- Plant Fuel Switching and Cold Weather
- Generation plant winter preparation

For 2011, the NERC lessons learned program also published eight individual relay protection systems lessons that address the following subjects:

- Special Protection Systems (SPS) maintenance precautions
- Relay Protection Systems coordination for close in faults
- Relay Protection Systems misoperations
- Power line carriers and misoperations
- Field revision to Relay Protection Systems
- Transmission Relaying – voltage transfer failure
- Transmission Relaying – removing unused components
- Use of out of date Relay Protection System technical prints

Other examples of lessons learned publications include SCADA modem vulnerabilities, Sub-synchronous interaction, backup control center operation and training.

A new companion program to the lessons learned initiative is the publication of best practices observed by NERC and the Regional Entities during the review and conduction of the event analysis program. Learning from best practices is as valuable as learning from lessons or near misses. Finally, the Reliability Risk Management (RRM) group is currently developing a human performance/human factors publications program that will be published on a quarterly basis. This will be accompanied by webinars to support the publications and create another forum for communication.

4. Alerts

As part of its normal course of business, NERC often discovers, identifies, or is provided with information that is critical to ensuring the reliability of the bulk power system (BPS) in North America. In order to effectively disseminate this information, NERC utilizes "Alerts" designed to provide concise, actionable information to the electricity industry. As defined in its Rules of Procedure, NERC Alerts are divided into three distinct levels, as follows:

- Industry Advisory - Purely informational, intended to alert registered entities to issues or potential problems. A response to NERC is not necessary
- Recommendation to Industry - Recommend specific action is taken by registered entities. Require a response from recipients as defined in the alert
- Essential Action - Identify actions deemed to be "essential" to BPS reliability. Require NERC Board of Trustees approval prior to issuance. Like recommendations, essential actions also require recipients to respond as defined in the alert.

Generally, NERC distributes Alerts broadly to users, owners, and operators of the BPS in North America utilizing its Compliance Registry. Reliability entities such as Balancing Authorities, Transmission Operators, Planning Authorities, Generation Owners, etc., are most often the recipients of NERC Alerts. Each reliability entity's primary compliance contact is responsible for registering any other individuals in its organization who should also be receiving Alerts from NERC.

Thus far, in 2011, NERC has published nine advisory alerts to industry on bulk power issues such as geomagnetic disturbances, cyber attacks exploiting RSA Secure ID authentication, Stuxnet and Night Dragon as well as transmission line facility ratings. Examples include:

- The Industry Advisory Alert on geomagnetic disturbances provided industry with a set of operation and planning actions to prepare for the effects of a severe Geo-Magnetic Disturbances (GMD) on the bulk power system. The Alert included categorized lists providing prospective examples based on industry experience that could be used by entities to reduce or mitigate the impacts of high levels of GIC resulting from severe GMD. This included operational planning actions to be considered after a severe GMD event (K>6) such as increasing import capability, increasing real and active reserves and increase attention to situation awareness and enhance surveillance procedures. Real-Time Operator Actions to be coordinated with the Reliability Coordinator after receiving a severe GMD warning (K>6) were identified, including increasing reactive reserves and decreasing load on susceptible equipment. The Alert also provided long term stakeholder actions to consider including modeling and simulation; relay review and inventory assessment. NERC also produced a draft guideline providing additional information on warning levels and information exchange[1]

- NERC also recently published an Alert "Reducing Human Error by the use of Configuration Control Practices. This emerging reliability issue trend was identified by NERC staff during their quarterly trend analysis of events. This publication includes five examples where a lack of configuration control was causal to events that occurred on the BPS as well as the ten configuration control practices that can be implemented to prevent these kinds of events from occurring

- FAC-008 is another example of where NERC utilized an Alert to identify a problem, issued an Alert Recommendation and continues to work on addressing those concerns. During 2011, NERC provided guidance and information to the Alert Recommendation for performing the FAC assessments, including guidance and information regarding the prioritization of Transmission and Generation Owner's facilities. This Assessment Plan Review Criteria was used to provide guidance to Regional Entity staff in review of assessment plans, provide further assistance to the Owners in meeting the intent of the Recommendation, and to respond to those issues. Two webinars were held, and NERC developed a semi-annual reporting spreadsheet to be used for providing information on their complete assessments. On July 15, 2011, NERC received the first High Priority Assessment report noting the progress each registered entity has made in completing their assessment plans. A significant number of assessments have been completed, and we anticipate the remainder will complete their assessments in the beginning of 2012

There are four levels of sensitivity utilized in deciding who within industry is able to view and receive a NERC Alert:

i. Public: No restrictions and posted to NERC's website alert page for all users, owners, and operators to view

[1] http://www.nerc.com/files/GMD_Guideline_v2_clean.pdf

ii. Private: Restrict to Internal Use and Necessary Consultants / Third-Party Providers
iii. Sensitive: Internal Use Only (Do Not Distribute Outside Your Company)
iv. Confidential: Limited Internal Distribution Decided Upon by an Officer of the Company

The NERC Alert system is working well, especially in the area of critical infrastructure where not all vulnerabilities can or should be addressed by a standard. In such cases, NERC Alerts are a key element in critical infrastructure protection. The system is well known by industry, handles confidential information and does so in an expedited manner. It does not require a NERC balloting process. The CIP Alerts use a HYDRA group which is comprised of many industry subject matter experts from across the BPS to help craft Alerts. The Alerts process has a mandatory "up to 5 days" of review time built in for FERC review. This is a required final review by FERC before NERC can release the Alert. After an Alert is sent out, the NERC Rules of Procedure provide for a series of questions with a mandatory response required for Level 2 and 3 alerts. The questions that are asked go to how the entity is responding to the Alert. We also receive feedback from the industry via webinars on the topic of the Alert.

5. Reliability Assessments and Performance Analysis: Metrics and Measures

While the aforementioned efforts in providing greater openness, transparency and focus on reliability are core to NERC's mission, the follow-on reliability assessment, system measurement and metrics development are critical to making informed decisions as to the efficacy of the work. Coupled with an understanding of reliability priorities, NERC assessments provide the appropriate measures of accomplishment and can lead to important recommendations to industry, policymakers and NERC, as well as provide important input into standards development.

The NERC Reliability Assessment and Performance Analysis (RAPA) program reviews, assesses, and reports on the overall electric reliability of the interconnected BPS in North America. As part of this assessment, the program identifies and analyzes the impact of key issues and trends that may affect reliability in the future, such as market practices, industry developments, potential technical challenges, technology implications, and policy changes. NERC reliability assessments are performed based on data supplied by users, owners, and operators of the BPS, and is gathered by the eight Regional Entities. This "bottom up" approach ensures that local and Regional issues are accounted for and that their relevance is understood.

NERC's primary objective in providing an assessment is to identify areas of concern regarding the reliability of the North American BPS and to make recommendations for that assessment as needed. The assessment process enables BPS users, owners, and operators to systematically document their operational preparations and to exchange vital system reliability information. These assessments are prepared by NERC in its capacity as the ERO. Section 39.11(b) of the U.S. FERC's regulations provide: *"The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional*

Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Each year, NERC prepares two seasonal (summer and winter) assessment and one Long-Term (10-year horizon) reliability assessment. These assessments provide an independent view of the seasonal and long-term reliability for the North American BPS while identifying trends, emerging issues, and potential concerns. Additional insights are offered regarding seasonal resource adequacy and operating reliability, an overview of projected electricity demand growth, Assessment Area highlights, and Assessment Area self-assessments.

Industry's plans to address reliability are gathered through data and detailed responses to NERC's reliability assessment questions. These questions use engineering experience on elements vital to measuring resource adequacy, ongoing concerns, lessons learned from previous seasons, and resource challenges. Each Assessment Area prepares a self-assessment in response to NERC's request for information on plans to address reliability considerations. The Assessment Area self-assessments are then made subject to scrutiny and review. These documented responses shed light on ongoing industry responses to reliability considerations such as variable generation integration, seasonal equipment preparations, operational procedures, etc.

Annually, the *Long-Term Reliability Assessment* forms the basis for the NERC reference case. This reference case incorporates known policy and regulation changes expected to take effect throughout the 10-year timeframe assuming a variety of factors such as economic growth, weather patterns, and system equipment behavior. A set of scenarios can then be developed from risk assessment of emerging reliability issues. These scenarios can then be compared to the reference case to measure and identify any significant changes to the BPS that may be required to maintain reliability. For this reason, NERC investigates each of these issues through structured industry technical committees and leveraged the expertise of the electric industry's broad knowledge base.

For NERC's annual long-term reliability assessment, the risk from standing and emerging reliability issues is measured based on their perceived likelihood of occurrence and potential consequences to reliability of the BPS. To qualify for consideration, emerging reliability issues must affect BPS reliability based on the following criteria:

- Exists for more than a single year in the 10-year study time horizon;
- Impacts reliability no sooner than three years into the future to allow for sufficient assessment and analysis; and
- Impacts reliability across at least one Regional Entity footprint and is not a local or sub-Regional reliability issue

For example, six issues were identified this year:

- Environmental regulations and impacts to bulk power system reliability
- Integration of Variable Generation (Operational and Planning affects)
- Increased gas generation to support variable generation
- Critical infrastructure protection
- System modeling Improvement and coordination

A risk assessment was completed to prioritize the resulting issues based on risk, defined as their likelihood of occurrence and consequence. Each issue was categorized as high impact, medium impact, or low impact to reliability. This risk assessment evaluated two timeframes: the risk to the BPS in the next one to five years (2011-2015), and the risk to the BPS in the next six to 10 years (2016-2020). Shifts in relative risk can be determined by evaluating the change between the two time periods.

For those issues identified as having a high likelihood of occurrence and high consequence to the reliability of the BPS, a detailed special reliability assessment can be completed to further understand the implications to reliability. Scenario analysis can also be performed to assess the robustness of the reference case against the scenario results, and to determine how the issues affect BPS reliability. The most recent instances include NERC's special reliability assessments on the integration of variable generation and resource adequacy impacts from potential environmental regulations. For example, in 2009, environmental regulations were determined to be a high-risk reliability issue; therefore, in 2010, NERC completed a detailed analysis to model what the potential effects could be to resource adequacy. These reports contain recommendations for policy makers, the industry and NERC.

Going forward in the long term, some issues become riskier due to technical and policy challenges, as well as uncertainties associated with determining solutions. These uncertainties continue to stress the planning functions, and will affect industry's ability to operate the system in a reliable manner. For example, in the face of accommodating large amounts of variable generation, the changing landscape of planning and operating the BPS must be finely tuned. Through the course of operator experience and implementing enhanced planning techniques, reliability must ultimately be maintained. For this reason, NERC pays considerable attention to these emerging and standing issues to provide input into NERC's reliability standards as well as supporting changes as needed in bulk power system planning and operations ensuring reliability is preserved, while meeting the potential challenges facing industry in the future.

To measure system performance and risk trends of the current bulk power system, NERC is also collecting reliability risk information, developing risk metrics and assessing the current state of reliability. The goal is to provide a view of risks to reliability based on historic performance. The objective is to integrate many ongoing efforts underway by providing technical analysis and feedback on risk attributes and reliability trends to stakeholders, regulators, policymakers and industry. The joint report development was led by NERC staff in collaboration with industry.

Since its inaugural report, NERC has advanced the development and understanding of risk attributes that impact reliability performance and the corresponding metrics that provide insight to the performance of the BPS. As this work proceeds, industry continues to investigate those risk attribute areas that enhance understanding and insights made evident for system reliability.

The *2011 Risk Assessment of Reliability Performance* begins a transition from a metric performance assessment to a more complete risk impact evaluation of reliability. This transition is expected to crystallize as more data becomes available and understanding of the data and trends matures. The annual report will provide a technically sound platform to ultimately communicate the effectiveness of ERO reliability programs, set the foundation of a learning organization and accountable Electric Reliability Organization, and present an overall view of risk impacts that affect reliability performance.

By addressing the key, measurable components of BPS reliability, metric development and assessment will provide insights, guidance, and direction to those areas in which reliability goals can be more effectively and sustainably achieved. Also, this analysis serves as a foundation to streamline and align the data and information arising from multiple technical groups, thereby providing efficient data and information transparency. The key findings and recommendations are envisioned as input to NERC's Reliability Standards and project prioritization, compliance process improvement, event analysis, reliability assessment, and critical infrastructure protection.

The ultimate goal is twofold. First, the report will illuminate the historical, overall BPS reliability picture. By using robust data, the reliability of the system can be explained and documented. Currently, there are no measures, datasets, or reports that explicitly and completely state the historical performance of the system.
Second, the report will help identify risk clusters and create actionable results for reliability improvement. These significant risk clusters can be selected as priority projects to develop coordinated and multifunctional solutions to relevant problems. NERC's assessment of the state of reliability will provide an industry reference for historical BPS reliability and analytical insights with a view to action. It will also enable the discovery and prioritization of specific, actionable risk control steps.

Conclusion

NERC continues to improve openness and transparency in a unique regulatory environment: striving to assist industry in understanding compliance, being a learning organization and working collaboratively with a clear focus on reliability as the main objective. The ERO continues to evolve, and these efforts, coupled with a commitment to accomplish the responsibilities as described in section 215 of the Federal Power Act, will enable the continued improvement in bulk power system reliability.

From: Kimberly Mielcarek
To: Kimberly Mielcarek
Subject: NERC Announcement - NERC Participates in FERC Technical Conference
Date: Tuesday, November 29, 2011 6:11:51 PM

Announcement

NERC Participates in FERC Technical Conference

Click here for Cauley's Panel 1 testimony
Click here for Cauley's Panel 2 testimony
Click here for FERC technical conference agenda

WASHINGTON, DC – The North American Electric Reliability Corporation (NERC) in the Federal Energy Regulatory Commission (FERC) two-day, technical conference that began Tuesday. The conference addressed priorities related to the reliability of the bulk power system. **NERC President and Chief Executive Officer Gerry Cauley** testified on both panels on Tuesday. On Wednesday, panelists will discuss emerging issues, including processes used by planning authorities and other entities to identify reliability concerns that may arise in the course of compliance with Environmental Protection Agency regulations, and the tools and processes available to address any identified reliability concerns.

For more information or assistance, please contact Kimberly Mielcarek.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

You are currently subscribed to nerc-info as: lpedowicz@npcc.org
To unsubscribe send a blank email to leave-1277198-325654.1ca6f85fb1574a8515cc07df72d3bfe0@listserv.nerc.com